BEFORE THE

DELAWARE PUBLIC SERVICE COMMISSION

PSC Docket No. 13-115

DIRECT TESTIMONY OF

DAVID E. DISMUKES, PH.D.

ON BEHALF OF THE

DIVISION OF THE PUBLIC ADVOCATE

AUGUST 16, 2013

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I. INTRODUCTION

Q. PLEASE STATE YOUR FULL NAME, ADDRESS, AND OCCUPATION.

A. My name is David E. Dismukes. My business address is 5800 One Perkins Place Drive, Suite 5-F, Baton Rouge, Louisiana, 70808. I am a Consulting Economist with the Acadian Consulting Group ("ACG"), a research and consulting firm that specializes in the analysis of regulatory, economic, financial, accounting, statistical, and public policy issues associated with regulated and energy industries. ACG is a Louisiana-registered Limited Liability Company, formed in 1995, and located in Baton Rouge, Louisiana.

Q. DO YOU HOLD ANY ACADEMIC POSITIONS?

A. Yes. I am a full Professor, Associate Executive Director, and Director of Policy Analysis at the Center for Energy Studies, Louisiana State University. I am also an Adjunct Professor in the E. J. Ourso College of Business Administration (Department of Economics), an Adjunct Professor in the School of the Coast and Environment (Department of Environmental Sciences), and a member of the graduate research faculty at LSU. Attachment A provides my academic vitae, which includes a full listing of my publications, presentations, pre-filed expert witness testimony, expert reports, expert legislative testimony, and affidavits.

Q. FOR WHOM ARE YOU APPEARING?

A. I am testifying on behalf of the Delaware Division of the Public Advocate ("DPA").

Q. HAVE YOU PREPARED ANY SCHEDULES IN SUPPORT OF YOUR RECOMMENDATIONS?

A. Yes. I have prepared 18 schedules in support of my direct testimony. Schedule DED-18 attaches all referenced responses of Delmarva to Staff, DPA, and other Intervenor Data Requests.

Q. WERE YOUR TESTIMONY AND SCHEDULES PREPARED BY YOU OR UNDER YOUR DIRECT SUPERVISION AND CONTROL?

A. Yes, they were.

Q. WHAT IS THE SCOPE OF YOUR TESTIMONY IN THIS PROCEEDING?

A. I have been retained by the DPA to provide an expert opinion on economic and policy issues associated with the reliability proposals raised by the Delmarva Power and Light Company ("DPL" or "the Company") that are included in its proposed reliability pro forma adjustment. I have also been asked to opine on the Company's proposed class cost of service study ("CCOSS") and proposed rate design.

Q. HOW IS YOUR TESTIMONY ORGANIZED?

A. My testimony is organized into the following sections:

- Summary of Recommendations
- Electric Reliability Pro forma Adjustment
- Class Cost of Service Study
- Rate Design

II. SUMMARY OF RECOMMENDATIONS

Q. WHAT IS YOUR RECOMMENDATION REGARDING THE COMPANY'S RELIABILITY PRO FORMA ADJUSTMENT?

A. I recommend that the Commission reject the Company's reliability pro forma Adjustment 26. The investments included in this adjustment are uncertain, and from a

policy perspective, not all of the investments are currently "used and useful" or entirely "known and measurable." Moreover, the investments included in Adjustment 26 are not supported by any cost-benefit or value of service studies which should be a pre-requisite for a forward-looking investment adjustment of this nature. The Company is currently exceeding the Commission's reliability standards; therefore, there is no pressing need to include post-test year investments in rate base. The Company's proposal will likely lead to inefficiencies because it removes positive incentives created by regulatory lag. In addition, the Company's past budgeting performance suggests that the budgeted investments included in Adjustment 26 may be overstated by as much as 25 percent or more. Most importantly, the omission of any defined review for appropriateness and reasonableness is a fatal flaw and should serve as a basis for summarily rejecting the Company's proposal.

Q. WOULD YOU PLEASE SUMMARIZE YOUR CCOSS RECOMMENDATIONS?

A. Yes. I recommend that the Commission adopt the Company's proposed CCOSS with the modifications of using a Total Distribution Plant allocator to allocate general and common plant accounts, using 100 percent number of customers to allocate Customer Service and Information Expense Accounts 907 through 910, and 100 percent number of customers to allocate Sales Expense Accounts 912-913.

Q. WOULD YOU PLEASE SUMMARIZE YOUR RATE DESIGN RECOMMENDATIONS?

A. Yes. My rate design recommendations can be summarized as follows:

- Revenue responsibilities for developing rates should be allocated using a two-step methodology. The first step limits the rate increase to any under-earning

class, and the second step distributes any remaining revenue deficiency across all other classes in proportion to their test year revenue.

- Existing customer charges should be increased for those classes where their current revenues are less than their customer-related costs to a level that moves towards their full cost of service.
- After developing the customer charges, the remaining costs are recovered through volumetric charges. For those classes that have a Demand Charge and a Delivery Service Rate, I recommend allocating the increase on an equal percentage basis between the demand charge and the delivery rate to maintain the existing relationship between the two components.

III. RELIABILITY PROPOSALS AND ADJUSTMENTS

Q. PLEASE EXPLAIN THE PRO FORMA ADJUSTMENT BEING PROPOSED BY THE COMPANY FOR SAFETY AND RELIABILITY PURPOSES.

A. The Company has requested pro forma Adjustment 26 in order to include in rate base the full estimated cost of proposed reliability enhancing investments that it claims will lead to benefits for all customers.[1]

Q. HOW LARGE ARE THESE PROPOSED RELIABILITY INVESTMENTS?

A. Schedule DED-1 summarizes the Company's request to include in rate base an additional $66.8 million associated with reliability plant closings that are projected to occur from January 2013 to December 2013. The plant closings included in the Company's Adjustment 26 proposal are for investments that, while inclusive of the current calendar year, will be made outside of its proposed test year in this

[1] Michael W. Maxwell, Direct Testimony, 8:13-16.

proceeding.[2] While some of these investment have been made over the course of the current year, others have not, making this adjustment difficult to reconcile with traditional regulatory "known and measurable" standards.

Q. DOES THE COMPANY ATTRIBUTE THE NEED FOR THIS ADJUSTMENT TO WHAT IT SEES AS A REGULATORY LAG PROBLEM?

A. Yes. Delmarva claims that the level of infrastructure investments needed to enhance and maintain system reliability "is far in excess of the book depreciation the Company is recovering in rates."[3] Similarly, the Company notes that it is not realizing sufficient customer and load growth to generate enough additional revenue to offset the costs of the needed reliability investment increase. The regulatory lag created by increased investment requirements and low revenue growth, outside of a rate case, puts the Company in a position where it claims it has been unable to earn a return comparable to other utilities with similar risk.[4]

Q. HAS THE COMPANY PROVIDED ANY ESTIMATES QUANTIFYING THIS REGULATORY LAG CHALLENGE?

A. No. The Company has not provided any detailed earnings attrition analyses that directly links under-earnings with its reliability investment requirements.[5] This is an important omission since an attrition analysis of this nature should be a prerequisite for any post-test year adjustment request. Thus, the Company's post-test year adjustment request is based simply upon broad assertions about what it believes could happen in

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[2] Jay C. Ziminsky, Direct Testimony, 27:12-16 and 28:11-14.
[3] Frederick J. Boyle, Direct Testimony, 5:9-12.
[4] Id. at 5:13-22.
[5] Company's Responses to Data Requests AG-REL-36 and AG-REL-37; Frederick J. Boyle, Direct Testimony, 2:21-3:11.

the future, not upon any quantitative analyses specifically estimating the relationship between future earnings and its anticipated reliability investments.

Q. HAS PEPCO HOLDINGS, THE COMPANY'S PARENT, REFERRED TO POST-TEST YEAR INVESTMENT ADJUSTMENTS (LIKE ADJUSTMENT 26) AS A FORM OF REGULATORY LAG MITIGATION?

A. Yes. In a recent presentation to investors, the Company's parent, Pepco Holdings ("PHI"), referred to this post-test year investment adjustment proposal as a method to mitigate against regulatory lag. As recently as the August 7, 2013 Investor Meetings, PHI told its investors that it has requested additional investments to rate base as a "regulatory lag mitigation measure" that would "recover additional reliability plant additions from January 2013 through December 2013 ($10.4 million of revenue)."[6]

Q. WHAT BENEFITS DOES THE COMPANY CLAIM CUSTOMERS WILL RECEIVE AS A RESULT OF ITS RELIABILITY INVESTMENTS?

A. The Company maintains that system reliability is not just good business practice, but that "electric system reliability is a minimum requirement for businesses in evaluating opportunities for economic investment, development and growth."[7] The Company also notes that reliability enhancement will attract new customers to Delaware.[8]

Q. HAS THE COMPANY EXPERIENCED ANY DIFFICULTIES IN MEETING THE COMMISSION'S RELIABILITY STANDARDS OVER THE PAST SEVERAL YEARS?

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[6] Pepco Holdings, Inc., "Second Quarter 2013 Earnings Call," August 7, 2013, p. 8.
[7] Michael Maxwell, Direct Testimony, 8:1-4.
[8] Id. at 8:6.

A. It does not appear to have experienced any difficulties, based on a review of its recent reliability statistics relative to the Commission's reliability standards. Schedule DED-2 shows that the Company has consistently exceeded the System Average Interruption Duration Index ("SAIDI") standard set by the Commission in Docket No. 50, the Electric Service Reliability and Quality Standards proceeding, over the past five years.

Q. HAS THE COMPANY BEEN ABLE TO IDENTIFY THE RELIABILITY INDICES THAT WERE IMPACTED BY PRIOR RELIABILITY INVESTMENTS?

A. No. In response to Staff Data Request PSC-REL-9, Delmarva indicated that it "selects and designs all reliability projects to decrease the frequency and duration of outages on the selected feeders. The requested data surrounding the changes at an individual project level is not available."[9]

Q. HOW DO THE COMPANY'S PROPOSED RELIABILITY INVESTMENT PROJECTIONS COMPARE TO HISTORIC LEVELS?

A. Schedule DED-3 shows that the Company spent a total of approximately $187.7 million for reliability-related capital projects for the years 2008 to 2012. The Company states that its total capital budget for reliability for the years 2013 to 2017 will be $309.1 million, representing an increase of 65 percent over historic trends. Schedule DED-4 provides historic detail for the Company's overall capital budget variance for a six-year period 2007-2012. The schedule shows that the Company has under-spent its capital budget by, on average, 3.5 percent per year. The Company has overspent, however, on reliability projects by close to 5 percent per year, on average, over a comparable time period.

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[9] Company's Response to Data Request PSC-REL-9.

Q. ARE THESE CAPITAL BUDGETING VARIANCES LARGE?

A. Yes. The Company's capital budget variance has been, at times, large. For example, Schedule DED-4 shows that in 2007, 2009, and 2012, reliability investments were over-budget by 25.1 percent, 12.1 percent, and 6.7 percent, respectively.

Q. HOW DO THE COMPANY'S RELIABILITY BUDGETS COMPARE TO ACTUAL EXPENDITURES?

A. Schedule DED-5 presents the Company's Reliability Enhancement Project ("REP") budgets compared to actual for the last two years, broken down by Work Breakdown Structure ("WBS") project number. This schedule also shows the projected expenditures for the years 2013 through 2017 at the project level of detail. As depicted, the variances at this level are in many instances significantly different from actual. For example, the Millsboro - Priority Circuit Improvement project, which is part of the current Adjustment 26, was over-budget by 182.5 percent in 2011, and under-budget by 46.8 percent in 2012. Likewise, the Distribution Automation-Christiana Substations project was budgeted at $1.5 million, but the Company expended $3.4 million, an increase of 131 percent.

Q. WERE THERE INSTANCES WHERE 2012 PROJECT BUDGETS WERE UNSPENT AND DEFERRED TO THE 2013 PRO FORMA TEST PERIOD?

A. Yes, there were several reliability projects which fit this criteria. As shown on DED-6, there were 14 REP projects that were 30 percent or more under-budget in 2012, several of which had no funds expended in 2012, yet now are included in the 2013 pro forma test year. Some reliability projects, Millsboro Sub Subscriber – BBW for example, were contained in the budgets for the years 2011 and 2012, but the

budgets were never spent. In the current case, the Company's pro forma adjustment includes $145,735 for this reliability project. Similarly, the Company's 2012 reliability budget included $1.0 million for Distribution Automation in the Christiana District; however, only $184,726 was expended in that year. The Company has included $1.5 million in the 2013 reliability budget and Adjustment 26 for this same effort. In total there were 14 reliability projects where a portion of the 2012 proposed project investment was shifted to the 2013 pro forma test period. Adjustment 26 contains $9.4 million related to projects that were deferred from prior years.

Q. HOW LARGE ARE THE COMPANY'S RELIABILITY INVESTMENTS RELATIVE TO ITS OVERALL CAPITAL BUDGET?

A. Schedule DED-3 shows that from 2003 to 2007 reliability investments accounted for 37 percent of the total capital budget. However, this increased significantly to 67 percent of the Company's capital budget for the period between 2008 and 2012. This share of the total anticipated capital budget will increase to 78 percent for the years 2013 to 2017.

Q. HOW DOES THE COMPANY DESCRIBE ADJUSTMENT 26?

A. According to the Company, the investments included in its Adjustment 26 are reliability-related projects that reflect "the continuing improvements that the Company is accomplishing in its reliability program and are provided to customers with the completion of every reliability asset that the Company puts in place."[10]

Q. WHAT TYPES OF PROJECTS ARE INCLUDED IN ADJUSTMENT 26?

A. The projects include the upgrading and improvement of distribution feeders, replacing and upgrading Underground Residential Distribution ("URD") cable

[10] Michael Maxwell, Direct Testimony, 8:14-16.

installations, substation improvements, and the installation of new technology and equipment such as Distribution Automation ("DA") systems.

Q. HAVE YOU PREPARED AN ANALYSIS OF THE COMPANY'S CLOSING TO PLANT FOR THE PROJECTS INCLUDED IN ADJUSTMENT 26?

A. Yes, and this analysis is shown on Schedule DED-7. As shown, for the three months ending March 2013, the Company has not met its forecasted closings on 45 of 95 projects. In addition, the Company estimated that it would have closed $21.0 million of its Adjustment 26 projects to plant in service as of March 2013, but it has closed $18.0 million. Schedule DED-7 also shows that for projects with closings less than forecasted, the amount not closed to plant as of March 2013 was $9.4 million compared to the forecast of $21.0 million.

Q. HAS THE COMPANY PERFORMED ANY COST-BENEFIT STUDIES OR VALUE OF SERVICE STUDIES IN CONNECTION WITH THE INVESTMENTS THAT ARE INCLUDED IN ITS PRO FORMA ADJUSTMENT 26?

A. No. The Company was unable to provide cost-effectiveness, cost-benefit, or value of service studies in connection with the reliability infrastructure investments included in this pro forma adjustment.[11] However, in a subsequent response to Staff discovery, the Company clarified its position by reiterating that although it did not conduct any cost-benefit or value of service studies, it employs a variety of other methods to ensure that investments are developed in an "economic" manner, such as: competitive bidding of materials and use of standard engineering design and work

[11] Company's Responses to Data Requests AG-REL-8 and AG-REL-7.

practices to ensure that the work is accomplished such that it meets all applicable standards.[12]

Q. ARE THESE METHODS THE SAME AS CONDUCTING A COST BENEFIT ANALYSIS?

A No. While the Company may employ a variety of methods to minimize its reliability investment costs, they are not the same as analyzing individual reliability programs for cost effectiveness. As an example, consider a reliability investment that is budgeted at $2 million. Assume that the Company employs a variety of management best practices that not only contains this estimate, but actually reduces the preliminary investment to $1.75 million. If the reliability investment only leads to $500,000 in benefits (say the value of avoided outages), this $250,000 in project development savings ($2 million less $1.75 million) will be irrelevant since the program fails most standard cost-benefit measures: at $1.75 million, the costs of the hypothetical program are still 3.5 times its benefits.

Q. DID THE COMPANY EXPRESS THE OPINION THAT ITS INVESTMENTS COULD NOT BE SUBJECTED TO COST BENEFIT ANALYSIS?

A. Yes. The Company noted that cost-benefit and value of service studies do not lend themselves to these types of investments since

> ... the company does not engage in traditional economic analysis of work because the costs, measured in dollars, and the benefits accrued, measured in reliability performance, do not lend themselves to those forms of analysis.[13]

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[12] Company's Response to Data Request PSC-REL-18.
[13] Id.

Q. DO YOU AGREE WITH THE COMPANY'S POSITION REGARDING THE MEASUREMENT OF RELIABILITY INVESTMENT COST-EFFECTIVENESS?

A. No. While it is true that some "qualitative" input can be used in a cost effectiveness analysis, it is not the case that quantitative methods should be summarily dismissed. In fact, Potomac Electric Power Company ("Pepco"), the Company's affiliate in the District of Columbia and Maryland, recently commissioned and filed a cost effectiveness analysis of its proposed selective underground proposals in those jurisdictions. This analysis used results from a 2008 Department of Energy ("DOE") meta-study to evaluate the reduction in outage costs to residential customers as a form of benefit associated with Pepco's selective undergrounding investments. Per unit values of outages were multiplied by estimated outage reductions (i.e., reliability improvements) associated with Pepco's selective undergrounding program. These undergrounding benefits were then compared to undergrounding program costs to develop an estimated net benefit. It is not clear why a similar methodology could not be applied to the Company's proposed reliability programs in Delaware.

Q. DID THE MARYLAND COMMISSION REQUIRE DELMARVA TO FILE A COST EFFECTIVENESS ANALYSIS WITH ANY OF ITS PROPOSED RELIABILITY INVESTMENTS?

A. Yes. The Maryland Commission, in what is referred to as its "Derecho Order," directed each electric distribution utility to file two separate plans with the Commission regarding storm resiliency improvements. First, electric utilities were required to file, on or before May 31, 2013 a plan outlining measures which can be completed in the next five years to accelerate reliability improvements to their distribution systems. Second,

utilities are required to file, on or before August 30, 2013, a more detailed, longer-term study that will serve as a platform for further proceedings considering appropriate standards for distribution system resiliency. The Commission explicitly directed the companies to include a cost-benefit analysis for each reliability improvement proposed in their short-term five-year plan filings. The Commission also requested each utility's long-term filings to assess how, and in what locations, their distribution systems would need to be improved in order to restore service following a major storm event to at least 95 percent of its customers within specified time frames. The Commission, in its discussion of the long-term plan filing requirements, reiterated the need for comprehensive cost-benefit analysis weighing the costs of improving the distribution system to different levels of storm resiliency.[14]

Q. DID DELMARVA MAKE A FILING CONSISTENT WITH THE MARYLAND COMMISSION'S DERECHO ORDER?

A. Yes, however, the filing is very general and does not include a comprehensive analysis of the cost-effectiveness of the Company's proposed reliability measures. The Maryland Commission has yet to rule on the completeness of each utility's filings, there is no Maryland Staff report making recommendations on these filings, nor is there any clear road map on how parties will be able to or should respond to these filings. Thus, while the Company may object to the methodological merits of being able to examine cost-effectiveness, that position would appear to be academic and one that PHI is going to need to reconcile very soon with regard to its retail regulators in neighboring jurisdictions.

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[14] In the Matter of the Electric Service Interruptions in the State of Maryland due to the June 29, 2012 Derecho Storm, Maryland Public Service Commission, Case No. 9298, Order No. 85385, pp. 3-4.

Q. HAS THE COMPANY EXPLAINED HOW THE REASONABLENESS OF THE FORECASTED RELIABILITY INVESTMENTS IN ADJUSTMENT 26 WILL BE EVALUATED?

A. No. It is unclear how or when any future review of these investments would be undertaken, at least as currently proposed by the Company. If the Commission approves the Company's pro forma adjustment, it could be opining on the propriety of these future investments today, before some of the investments are ever made and determined to be used and useful. The omission of any review for reasonableness and appropriateness is a fatal flaw that in and of itself should serve as a basis for rejecting the Company's pro forma Adjustment 26.

Q. HAS THE COMPANY UNDERTAKEN ANY EVALUATIONS OR ANALYSES FOR THE PURPOSE OF IDENTIFYING PROJECTS THAT WOULD IMPROVE RELIABILITY?

A. Not specifically. In response to discovery on this matter, the Company described its budgeting process, provided a Work Request process used to identify the scope of projects, provided its "Asset Management/Asset Performance Planning and Equipment Condition Assessment" procedures, provided a document entitled "Description of Delmarva Power's Planning Process," and provided a list of approved expenditures. None of these documents contained specific analyses that examined the individual projects included in its pro forma adjustment, and none provided any estimates on how each would contribute to future reliability improvements.[15] Thus, while the Company continually claims that pro forma Adjustment 26 includes forecasted investments to enhance reliability, it has not provided any quantification of

[15] Company's Response to Data Request AG-REL-11.

those reliability benefits in terms of avoided outages or reduced outage minutes. As a result, there is no way that the reliability investments included in pro forma adjustment 26 can be shown to be just and reasonable.

Q. ARE THERE OTHER PROBLEMS WITH THE COMPANY'S POST TEST YEAR FORECASTED PRO FORMA ADJUSTMENT 26?

A. Yes. The proposed reliability investment adjustment removes the regulatory lag and the associated incentives for minimizing over-capitalization. Regulatory lag has long been recognized as a key component of the overall regulatory process given the discipline it can impose on utility operational and investment decisions. Regulatory lag prevents utility regulation from devolving into a "cost-plus" regulatory approach that simply passes through costs on a dollar for dollar basis to ratepayers, and can lead to cost and investment inefficiencies. The cost-plus regulatory approach also shifts a considerable amount of performance-related risk away from utilities and onto ratepayers and leads to inefficient outcomes. This was recognized as early as the 1960s and has come to be known as the "Averch-Johnson" or "A-J" effect.

Q. IF THE COMPANY'S REGULATORY LAG MITIGATION MEASURE (ADJUSTMENT 26) IS ADOPTED, WOULD IT REDUCE THE COMPANY'S RISK?

A. Yes. The Company's proposal is asymmetrical and unfairly tilts the risk scale in its favor. If adopted, it would unfairly shift regulatory, investment, and performance risk away from DPL and onto ratepayers. This result alone should compel the Commission to reject the forecasted investments from the Company's pro forma adjustment. If the Commission decides to accept the Company's proposal, then it should consider an explicit adjustment to the Company's allowed ROE as a compensation to ratepayers,

or take the risk-shifting nature of the Company's proposal into account when considering the range of potential ROEs the Commission may select in this proceeding.

Q. PLEASE EXPLAIN HOW REGULATORY RISK IS SHIFTED TO RATEPAYERS.

A. Utilities typically control the timing of rate case filings. Accordingly, utilities enjoy the ability to request higher rates, as well as the protection afforded by a price floor that allows shareholders to retain benefits created by regulatory lag. Thus, in times of over-earning, utilities are not likely to elect to file a rate case so as to keep the gains of regulatory lag for themselves and their shareholders. In times where a utility is under-earning, it can make an application to increase rates. The Company's forecasted investments will exacerbate these timing risks by allowing the Company to increase rates for projected investments that may never be evaluated in the future for reasonableness and appropriateness.

Q. DO YOU AGREE WITH THE SUGGESTION EMBEDDED IN THE COMPANY'S REQUEST THAT PRESUMES REGULATORY LAG IS SOMEHOW BAD AND NEEDS TO BE CORRECTED?

A. No. The presence of regulatory lag in and of itself does not create a policy justification for the Company's forecasted investment adjustment proposal. Regulatory lag can lead to both costs and benefits for a regulated utility. Regulatory lag creates opportunities for utilities to achieve gains as well as losses. The simple fact that regulatory lag creates "opportunities," and not guarantees, is one of the reasons why regulatory lag is considered efficiency-enhancing. There is a long and rich history in

the practice and theory of utility regulation supporting these efficiency-enhancing conclusions. Thus, there is no inherent or *a priori* policy rationale for reaching the conclusion that regulatory lag is bad or has a consistently negative implication. If anything, past thought and practice in utility regulation supports rejection of proposals of this nature on a policy basis.

Q. HAVE OTHER COMMISSIONS REJECTED SIMILAR REGULATORY LAG MITIGATION PROPOSALS?

A. Yes. The Maryland Public Service Commission rejected an analogous adjustment requested by Baltimore Gas & Electric Company ("BGE") in its last rate case[16] on the basis that the investments were "not used and useful" or "known and measurable" noting:

> We find that the Company has failed to support its proposal to reflect projected, estimated safety and reliability investments. Not only are these investments not currently used and useful, they are not even known and measurable. While we do not question the Company's good faith to arrive at such an estimate, we note that by the Company's own admission estimates, forecasts and budgets can prove unreliable. In footnote 7 to BGE's Exhibit 13, the Company acknowledged that due to the Derecho storm in 2012 that 'work on planned investments was shifted from non-revenue producing safety and reliability investments to storm restoration.' Thus, even with the best of intentions, budgets and forecasts can prove unreliable. We conclude that it would not be just and reasonable to saddle customers with almost $20 million in additional utility costs based upon estimates that are not fully reliable.[17]

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[16] Baltimore Gas & Electric Company; In the Matter of the Application of Baltimore Gas and Electric Company for Adjustments in its Electric and Gas Base Rates, Public Service Commission of Maryland, Case No. 9299. Order Dated February 22, 2013, pp. 20-21.

[17] Baltimore Gas and Electric; In the Matter of the Application of Baltimore Gas and Electric Company for Adjustments in its Electric and Gas Base Rates, Case No. 9299, Order Dated February 22, 2013, p. 37 (Emphasis added).

Q. WHAT IS YOUR RECOMMENDATION REGARDING THE COMPANY'S RELIABILITY ADJUSTMENT 26 PROPOSAL?

A. I recommend that the Commission reject the Company's proposed Adjustment 26. The reliability investments included in this adjustment are uncertain, and from a policy perspective, not all of the investments are currently "used and useful" or entirely "known and measurable." Moreover, the investments included in Adjustment 26 are not supported by any cost-benefit or value of service studies, which should be a prerequisite for a forward-looking investment adjustment of this nature. The Company is currently exceeding the Commission's reliability standards, thus there is no pressing need to include post-test year investments in rate base. The Company's proposal will likely lead to inefficiencies by removing the positive incentives created by regulatory lag. Likewise, the Company's past budgeting performance suggests that the budgeted investments included in Adjustment 26 may be overstated by as much as 25 percent or more. Most importantly, the omission of any defined review for appropriateness and reasonableness is a fatal flaw and should serve as a basis for summarily rejecting the Company's proposal.

Q. DO YOU HAVE AN ALTERNATIVE RECOMMENDATION IF THE COMMISSION DOES NOT ACCEPT YOUR PRIMARY RECOMMENDATION?

A. Yes. I have performed an analysis of the specific projects included in Adjustment 26. Based upon this analysis, at least $39.8 million should be removed from the Company's pro forma adjustment, as the costs have not been justified as described below.

Q. WOULD YOU PLEASE DESCRIBE THE SPECIFIC CONCERNS YOU HAVE ABOUT THE PROJECTS INCLUDED IN PRO FORMA ADJUSTMENT 26?

A. Yes, I found several problems with the proposed projects. These include the inclusion of non-specific blanket projects, projects which were described as "as needed" or "as identified," projects for emergency repairs and restoration, projects associated with spares, and projects not specifically identified as being associated with any reliability improvements. All projects proposed for inclusion in Adjustment 26 are shown on my Schedule DED-8.

Q. WOULD YOU PLEASE DESCRIBE SCHEDULE DED-8?

A. Yes. This schedule contains a list of the Company's reliability projections included in Adjustment 26. The first column contains the WBS, the second column contains a short description of the project, the next column contains a more detailed explanation of the project if it is included in the Reliability Enhancement Plan ("REP"), and the fourth column contains the detailed description for Non-REP projects.

Q. WHAT IS THE DIFFERENCE BETWEEN A REP PROJECT AND A NON-REP PROJECT?

A. The difference between a REP project and a non-REP project was described by the Company as follows:

> The REP is a way to combine the efforts into one program that discuss the commitment that the Company is making to continuously improve its reliability performance. The REP is an integral part of the Company's overall expansion-related efforts. REP work is identified based on the following work criteria, Priority Feeder Upgrades, Underground Residential Distribution Cable Upgrades (URD), Distribution Automation, Feeder Reliability Improvements, Conversions, Substation Reliability

Improvements, Feeder Load Relief. Non-REP projects are comprised of all other work.[18]

Q. ARE THE DESCRIPTIONS OF REP VERSUS NON-REP PROJECTS SIMILAR?

A. Yes, although there is apparently a distinction between the functions they are intended to accomplish. When asked to clarify what "factors and criteria the Company uses to designate which of seemingly similar project types should be considered REP versus non-REP," the Company merely referred to the response to PSC-REL-8, which provides little if any explanation of how similarly-named projects end up in either category. This raises questions as to whether or not projects are moved between categories at management's discretion.

Q. WOULD YOU DESCRIBE THE RELIABILITY PROJECTS INCLUDED IN ADJUSTMENT 26 RELATED TO BLANKET PROJECTS THAT ARE NOT SPECIFICALLY DEFINED?

A. Yes. Schedule DED-8 identifies three projects that are not specifically defined: the Millsboro District Miscellaneous Relay project; the Christiana District Miscellaneous Relay Blanket project; and the Christiana District Substation Planned Improvements. The latter project is described as: "Blanket project – Planned for capital improvements including control house upgrade, roof replacements and cable troughs, etc." The Company described these as blanket work orders that do not have a defined scope. The Company's description further suggests that these projects are intended for very simple miscellaneous relay upgrades that **may** need to be completed. The total amount budgeted for these three projects in 2013 is $206,869. The Commission should not

[18] Company's Response to Data Request PSC-REL-8.

include projects in rate base without a defined scope and which may or may not be completed.

Q. DOES THE COMPANY'S PRO FORMA ADJUSTMENT ALSO INCLUDE COSTS RELATED TO SPARES?

A. Yes. Schedule DED-8 shows that the Company has included $2.3 million associated with Christiana District Spare Distribution Transformers and Millsboro District - PHI Spare Transformers. I disagree with including spare transformers in rate base without additional justification by the Company. The Company has not demonstrated that that the transformers are needed for reliability purposes. I recommend the budgeted amounts for these projects be excluded from Adjustment 26.

Q. WOULD YOU DESCRIBE THE PROJECTS THAT USE THE TERMS "AS NEEDED" OR "AS IDENTIFIED"?

A. Yes. There are two projects which are described as "as needed" or "as identified."

- UDLNRM4CR, Wilmington Network Upgrade, Upgrade the aerial sections of the Wilmington Network by replacing poles, wires and adding distribution transformers as needed.
- UDSNRD8FD Christiana District Distribution Substation Bushing Replacements, Replace bushing sets on transformers, in which the bushings have deteriorated or have not met testing specifications. Recommend replacing Type "U" or as identified by Maintenance testing data. Estimate based on 4 projects per year for 2013-2014, then 3 projects per year 2015-2017.

These two projects classified as "as needed" and "as identified" are not well-defined and certain, nor has it been determined that they have specific known and measurable reliability benefits for ratepayers. Therefore, the Commission should remove $570,713 from pro forma Adjustment 26.

Q. WHAT IS THE NEXT GROUP OF PROJECTS THAT YOU RECOMMEND BE REMOVED FROM PRO FORMA ADJUSTMENT 26 IF THE COMMISSION DOES NOT REMOVE THE ENTIRE ADJUSTMENT?

A. I recommend that the Commission remove projects associated with what appear to be one-time emergency repairs. I disagree with Delmarva's inclusion of these in rate base since they have not been identified as being necessary for improving reliability. Schedule DED-8 shows that there are four projects, totaling $13.7 million of the Company's 2013 budget, which fall within this category:

- UDLBRM3M1, Funds necessary for the emergency restoration of customers;
- UDLNRM3C1, Capital work needed to maintain or restore electric service;
- UDSBRD71D, Millsboro District Emergency Repair/Replacements Distribution Sub Equipment;
- UDSNRD71D, Funds set aside for contingencies across distribution substations in Delaware.

I recommend that the Commission require the Company to demonstrate that these projects will in fact improve system reliability. Absent such a showing, the Commission should reject these projects from inclusion in Adjustment 26.

Q. THE PROJECTS DESCRIBED ABOVE ARE CONSIDERED NON-REP. WHAT IS YOUR RECOMMENDATION CONCERNING THE REMAINING NON-REP

PROJECTS INCLUDED IN ADJUSTMENT 26?

A. I recommend that the remaining projects not included in the REP also be removed from Adjustment 26 since the REP, according to the Company, governs its reliability investment planning. Adjustment 26 includes many investments that are not identified in the Company's REP. The Company has indicated that only those projects included in the REP are related to improving reliability performance.[19] If the Commission determines that some portion of Adjustment 26 should be included in rate base, an additional $22.5 million of Delmarva's proposed adjustment should be removed because the costs are not directly linked with reliability improvements.

Q. CAN YOU SUMMARIZE YOUR ALTERNATIVE RECOMMENDATION?

A. Yes. If the Commission does not accept my primary recommendation to reject the Company's proposed Adjustment 26, then I recommend that the Commission reduce this proposed pro forma adjustment by $39.8 million. This removes from Delmarva's request non-specific blanket projects, projects which have been described as "as needed" or "as identified," projects identified for emergency repairs and restoration, projects associated with spares, and all other projects not specifically part of the REP.

IV. CLASS COST OF SERVICE STUDY

A. INTRODUCTION

Q. WHAT IS THE PURPOSE OF A COST OF SERVICE STUDY?

A. A cost of service study ("CCOSS") is a method by which utility costs and revenues are reconciled across different customer classes. The goal of the study is to determine the cost of providing service to either a particular jurisdiction or a particular customer class, and the revenue contribution each makes to cover those costs. The

[19] Company's Response to Data Request PSC-REL-8.

results of a CCOSS produce a rate of return and revenue requirement that can be used as a tool in developing the revenue responsibility and rates for each rate class.

Q. HOW IS A CCOSS PERFORMED?

A. Typically, a CCOSS is performed in three distinct steps: functionalization; categorization; and allocation. The first step in this process, functionalization, simply defines costs based upon their nature. In the specific case of distribution-only electric utilities, most utility costs are associated with providing distribution services, so most distribution-only electric utility costs are identified or functionalized as distribution-related. The next step of the process "categorizes" each of these respective costs into a particular type of cost, including those that are demand-related, energy-related, or customer-related. The last step of the process "allocates" each of these costs to a respective customer class.

Q. IS THIS A RELATIVELY SIMPLE PROCESS?

A. No. Some costs can be clearly identified and directly assigned to a function or category, while several others are more ambiguous and difficult to assign. The primary challenge in conducting a CCOSS is the treatment of what are known as "joint and common" costs. Given their shared or integrated nature, these joint and common costs can often be difficult to compartmentalize into any particular function or category. Therefore, unique allocation factors are utilized in a CCOSS to classify joint and common costs. The process of developing these cost allocation factors can become subjective and imbued with various interpretations and emphases.

Q. CAN YOU EXPLAIN WHAT YOU MEAN BY DEMAND-RELATED COSTS?

A. Yes. Demand-related costs are associated with meeting maximum electricity demands. Electric substations and line transformers are designed, in part, to meet maximum customer demand requirements. The most common demand allocation factors used in a CCOSS are those related to system coincident peaks ("CP") or non-coincident customer class peaks ("NCP").

Q. HOW ARE ENERGY-RELATED COSTS DEFINED?

A. Energy-related costs are defined as those that tend to change with the amount of electricity sold and can be thought of as volumetric-related costs.

Q. WHAT ABOUT CUSTOMER-RELATED COSTS?

A. Customer-related costs are those associated with connecting customers to the distribution system, metering household or business usage, and performing a variety of other customer support functions.

Q. HOW DO COST OF SERVICE STUDIES RELATE TO COMMONLY QUOTED ECONOMIC PRINCIPLES?

A. CCOSSs are also referred to as "fully allocated cost studies" since they allocate test year revenues, rate base, expenses, and depreciation to various different jurisdictions and customer classes based upon a series of different allocation factors. The purpose of the CCOSS is to estimate the cost responsibility for various jurisdictions and customer classes, which in turn are used to develop rates. At the core of a CCOSS is a set of historic book costs for the Company that has accumulated over decades. Rates are, therefore, based upon historic average costs, whereas economic theory suggests that the most efficient form of pricing in perfectly competitive markets should be based upon marginal costs. However, distribution utilities do not operate in

perfectly competitive markets and, by their very nature, are natural monopolies. Thus, reaching the ideal pricing formula outlined in economic theory is impossible since the nature of natural monopolies makes pricing difficult in the presence of declining average costs, coupled with a number of joint and common costs. Added to this problem is the fact that the costs utilized by a CCOSS are historic and static, not dynamic and forward-looking, undermining many experts' cost-causation/pricing claims. There is no one single correct answer that is revealed in a CCOSS, and it is often up to regulators to exercise their appropriate judgment regarding the nature of these costs and the implications they have in setting fair, just, and reasonable rates.

Q. WHAT CONTROVERSIES ARISE IN THE ANALYSIS AND COMPARISON OF VARIOUS CCOSS METHODOLOGIES?

A. The CCOSS process is significantly different than the revenue requirement or cost of capital phase of a typical rate case. While the latter two activities are dedicated to determining how much revenue will be recovered through rates, the CCOSS process determines how those revenues will be recovered, and through which customer rates. The primary controversy with the evaluation of various CCOSS results often rests with determining whether revenues (costs) will be recovered strictly by the peak load contributions of each customer class, or whether the approach will be tempered through the use of peak and off-peak usage considerations. Methodologies that are heavily biased to peak considerations (over non-peak or energy), for instance, can tend to prejudice relatively lower load-factor customers, such as residential and small commercial customers, and prefer larger customer classes and off-peak customers. These approaches also fail to fully capture the basic commodity being sold by the utility

which is electricity, and how the value of that commodity varies by the amount purchased by different customer classes.

Q. COULD YOU PLEASE DESCRIBE THE DEMAND ALLOCATORS USED WITHIN THE COMPANY'S CCOSS?

A. Yes. The Company uses three separate allocators to distribute different demand-related costs: Primary Demand ("DEMPRI"), Secondary Demand ("DEMSEC") and Line Transformer Demand ("DEMTRNSF").[20] These three allocators are derived from two separate measurements of electric demand, the first being a Class Maximum Diversified Demand ("Class MDD") and the second being a sum of customer maximum non-coincident demands ("Customer NCP").[21] DEMPRI is derived based on 100 percent Class MDD across all customer classes, while DEMSEC is based on 50 percent Class MDD and 50 percent Customer NCP excluding large secondary, primary, and transmission General Service.[22] Finally, DEMTRNSF is derived using 50 percent Class MDD and 50 percent Customer NCP, while excluding primary and transmission General Service and Class MDD for large secondary General Service.[23]

Q. COULD YOU PLEASE DESCRIBE THE COMPANY'S CLASS MDD MEASURE OF DEMAND?

A. The Class MDD is a traditional measure of non-coincident customer class peaks, or NCP, measured as the maximum hourly system demand attributable to each rate class for a given year, which in this case is the 2011 calendar year.[24] The DEMPRI allocator utilized in the Company's CCOSS is simply the sum of the individual

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[20] Elliott P. Tanos, Direct Testimony, Schedule EPT-1.
[21] Id. at Schedule EPT-1 and 9:21 to 10:9.
[22] Id. at Schedule EPT-1.
[23] Id. at Schedule EPT-1.
[24] Company's Responses to Data Requests PSC-COS-18 and PSC-COS-28.

class MDDs, which in turn is used to allocate Account 361 (Structures & Improvements); Account 362 (Station Equipment); primary voltage system assets of Account 364 (Poles, Towers and Fixtures) and Account 365 (Overhead Conductors and Devices); Account 366 (Underground Conduit); and Account 367 (Underground Conductors and Devices).[25]

Q. COULD YOU PLEASE DESCRIBE THE COMPANY'S CUSTOMER NCP MEASURE OF DEMAND?

A. The Customer NCP measure of demand is an aggregation of each customer's maximum hourly system demand within a rate class.[26] Not all customers possess sufficient metering equipment for the Company to directly measure individual demands, so calculations of the Customer NCP also rely heavily on estimations from a sample of load research meters dispersed throughout the Company's service territory.[27]

Q. HOW IS THE CUSTOMER NCP MEASURE OF DEMAND USED TO ALLOCATE COMPANY COSTS IN ITS CCOSS?

A. As described previously, the Customer NCP measure of demand is combined using a simple average with the Company's Class MDD allocator to create the DEMSEC and DEMTRNSF allocators. However, the DEMSEC allocator excludes Customer NCP and Class MDD measures of demand for large secondary, primary, and transmission General Service customer classes. The DEMTRNSF allocator is similar to the DEMSEC allocator, but includes Customer NCP for large general service customers within its calculations.[28]

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[25] Elliott P. Tanos, Direct Testimony, Schedule EPT-1.
[26] Company's Response to Data Request PSC-COS-29.
[27] Company's Response to Data Request AG-COS-16.
[28] Elliott P. Tanos, Direct Testimony, Schedule EPT-1.

Q. WHICH ACCOUNTS ARE ALLOCATED USING THE DEMSEC AND DEMTRNSF ALLOCATION FACTORS?

A. The DEMSEC allocator is used by the Company to allocate secondary voltage system assets, defined by the Company as secondary voltage assets attached to distribution plant Accounts 364 through 367, and overhead and underground services.[29] The DEMTRNSF allocator is used solely by the Company to allocate distribution plant Account 368 (line transformers).[30]

B. COMPLIANCE WITH ORDER NO. 8011

Q. HAVE YOU REVIEWED THE COMMISSION'S ORDER NO. 8011 ISSUED IN PSC DOCKET NO. 09-414?

A. Yes. Staff found numerous deficiencies with the Company's CCOSS in that proceeding, including: (1) the CCOSS was not updated to include the Company's proposed adjustments to test year data; (2) the Company used Delaware-specific load data for non-residential classes, but PEPCO-Maryland average load factors for residential customers; (3) the Company used a 1996 system loss study to develop demand and energy allocators; (4) the Company did not use weather-normalized data; (5) the Company failed to update the CCOSS for certain post-filing corrections; (6) the Company used a different overall rate of return from what the Company was proposing; and (7) the Company allocated service facilities to customers using demand-related allocators rather than customer-related allocators.[31] The Settlement Agreement approved in that proceeding included a provision to convene a CCOSS workshop for

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[29] Id. at Schedule EPT-1.
[30] Id. at Schedule EPT-1.
[31] In the Matter of the Application of Delmarva Power & Light Company for an Increase in Electric Base Rates and Miscellaneous Tariff Changes (Filed September 18, 2009), Delaware PSC, Docket No. 09-414, Order No. 8011, ¶ 314.

purposes of developing an agreement on CCOSS approaches to be used in future rate cases.[32]

Q. DID THE COMPANY CONVENE THE AGREED TO CCOSS WORKSHOP?

A. Yes. The workshop was held on August 24, 2011, at the Commission offices in Dover.[33] According to the event agenda, the workshop covered issues associated with obtaining load data for Delaware residential customers, weather normalization, system losses analysis, allocation of customer-related services, geographic information system ("GIS") uses to functionalize system plant assets, and other related matters.[34]

Q. HAS THE COMPANY MODIFIED ITS CCOSS PRACTICES IN WAKE OF THE AUGUST 24, 2011, WORKSHOP?

A. Yes. The Company notes that it has made five separate changes to its CCOSS practices in wake of the August 24, 2011 workshop that include:

1. The use of Delaware-specific load survey data to estimate residential non-coincident peak demands.
2. The use of weather normalized sales and revenue data within the CCOSS.
3. Utilization of an updated analysis of system losses within the CCOSS.
4. Account 369 – Service Lines are now allocated on the basis of a derived allocator.
5. Traffic signal service customers are now disaggregated from the general street lighting class in the CCOSS.[35]

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[32] Id. at 316.
[33] Elliot P. Tanos, Direct Testimony, 7:22-23.
[34] Company's Response to Data Request PSC-COS-22.
[35] Id.

Q. HAVE YOU REVIEWED THE COMPANY'S LOAD SURVEY METHODOLOGY?

A. Yes. The Company provided information regarding its load research activities that includes electronic printouts of software programming code and its estimated statistical parameters.[36] The analyses show that the Company used Delaware-exclusive load data for the 12 months ending 2011 in determining both Class MDD and Customer NCP measures of demand usage.[37]

Q. HAVE YOU REVIEWED THE COMPANY'S WEATHER NORMALIZED SALES AND REVENUE DATA USED IN THE CCOSS?

A. Yes. The Company weather-normalized test year 2012 sales and revenue data associated with the residential and commercial portions of sub-transmission general service rate classes. The overall effect of the Company's weather-normalization varies by rate class, but results in a total upward revenue adjustment in the CCOSS model of 0.22 percent.[38]

Q. HAVE YOU REVIEWED THE COMPANY'S UPDATED ANALYSIS OF SYSTEM LOSSES?

A. Yes. The Company hired Management Application Consulting, Inc. ("MAC") to perform an analysis of system losses for the 2011 calendar year. This report was finalized by MAC in February of 2013 and provided through discovery to parties for review in this proceeding.[39]

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[36] Company's Response to Data Request PSC-COS-18.
[37] Id.
[38] Company's Response to Data Request AG-GEN-10.
[39] Company's Response to Data Request PSC-COS-18.

Q. HAVE YOU REVIEWED THE COMPANY'S METHODOLOGY FOR ALLOCATING ACCOUNT 369?

A. Yes. The Company conducted an accounting cost study which estimated the average cost per customer receiving service through overhead and underground secondary service lines.[40] The Company's revised Account 369 allocator allocates slightly more costs to residential customers (91.9 versus 87.6 percent) than an allocator based solely on total number of customers receiving service at secondary voltage levels. Monetarily, this results in an allocation change to the Company's total distribution plant of slightly more than $3.7 million relative to a total distribution plant value of nearly $974 million.[41]

Q. HAS THE COMPANY DISAGGREGATED THE TRAFFIC SIGNAL AND GENERIC STREET LIGHTING SERVICE CLASSES IN ITS CCOSS?

A. Yes; however, summary results presented by the Company and in my supporting schedules still aggregate these services within the street lighting service class. The traffic signal class only accounts for slightly more than 1.0 percent of street lighting service revenues, or 2.1 percent of allocated operating expenses, to the street lighting service customer class. The difference in the relative rate of returns for these two services also differs by only 0.17 under the Company's proposed allocations.[42]

Q. HAS THE COMPANY COMPLIED WITH THE SETTLEMENT AGREEMENT IN PSC DOCKET NO. 09-414?

A. Yes; however, there are still deficiencies in the Company's COS methodology. For example, load data used in the Company's CCOSS is based on usage for the 12

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[40] Company's Response to Data Request PSC-COS-18.
[41] Elliott P. Tanos, Direct Testimony, Schedule EPT-1.
[42] Id.

months ending 2011, a full year prior to the test year.[43] Furthermore, information provided by the Company shows that it has not verified the validity of its load research samples since an analysis was conducted in April 2008 using September 2007 billing data.[44] When asked to provide internal documents regarding the Company's policy for updating load research samplings, the Company stated, "Delmarva has no written policy on sample renewal but relies on the quality of current sample load data statistics to dictate sample maintenance needs."[45]

C. ALTERNATIVE CCOSS AND RECOMMENDATIONS

Q. DO YOU DISAGREE WITH ANY OF THE ASSUMPTIONS OR ALLOCATION FACTORS INCORPORATED IN THE COMPANY'S PROPOSED CCOSS?

A. Yes. I disagree with two allocation factors used by the Company in its CCOSS: (1) the Company's use of a labor allocator to allocate general and common plant accounts and (2) the Company's use of an allocator derived from a 50 percent weight on number of customers and 50 percent energy sales to allocate Accounts 907 through 913.

Q. HAVE YOU PREPARED AN EXHIBIT THAT COMPARES THE COMPANY'S ALLOCATION FACTORS TO THE ONES YOU ARE RECOMMENDING?

A. Yes. Schedule DED-9 compares my proposed allocation factors to the Company's for the CCOSS. The first column in the schedule lists the account name, and the second and third columns compare the Company's proposed allocation method with my recommendations.

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[43] Company's Response to Data Request PSC-COS-18.
[44] Company's Response to Data Request AG-COS-19.
[45] Company's Response to Data Request AG-COS-25.

1. GENERAL AND COMMON PLANT ACCOUNTS

Q. PLEASE EXPLAIN HOW GENERAL AND COMMON PLANT ACCOUNTS ARE TYPICALLY ALLOCATED.

A. As stated previously, all CCOSS and rate design analyses incorporate a degree of subjectivity, with often more than one method being a valid allocation method. There are three accepted methods for allocating general and common plant accounts. These are discussed in the Electric Utility Cost Allocation Manual published by the National Association of Regulatory Utility Commissioners ("NARUC," generally "NARUC Manual"). The first is on the basis of overall total plant (or in this case total distribution plant). This method is supported by the theory that general plant supports the other operations of the utility, such as the distribution of electric power. The second commonly-accepted allocation methodology is to allocate general and common plant on the basis of square footage of office space designated to each function of the utility's operations (i.e. distribution and customer accounting and information). The third commonly-accepted method of allocating general and common plant is on the basis of operating labor ratios.[46]

Q. IS THE COMPANY'S USE OF A LABOR ALLOCATOR TO ALLOCATE GENERAL AND COMMON PLANT CONSISTENT WITH THE THREE ACCEPTED ALLOCATION METHODS YOU LIST?

A. Yes. The Company's labor allocator is similar in function to the use of operating labor ratios discussed in the NARUC Manual. However, the NARUC Manual is not

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[46] National Association of Regulatory Utility Commissioners, Electric Utility Cost Allocation Manual, January 1992, p. 105.

intended to be prescriptive, as the preface section of the manual clearly states.[47] I do not agree with the use of such an allocator given the unnecessary complexity this approach adds to the CCOSS, particularly when there is a more straight-forward allocation method like my recommended use of a total distribution plant allocator.

2. CUSTOMER SERVICE, INFORMATION, AND SALES EXPENSES

Q. PLEASE EXPLAIN THE COMPANY'S ALLOCATION OF COSTS ASSOCIATED WITH CUSTOMER SERVICE AND INFORMATION EXPENSES (ACCOUNTS 907 – 910) AND SALES EXPENSES (ACCOUNT 913).

A. The Company utilizes two allocators, CSERV and CSALES,[48] to distribute all Customer Service, Information, and Sales Expenses listed as Accounts 907 through 913. These two allocators are identical in every respect and are calculated by giving 50 percent weight to total number of customers and 50 percent weight to total energy sales.[49]

Q. DO YOU AGREE WITH THIS ALLOCATION METHOD?

A. No. As stated previously, all CCOSS and rate design analyses incorporate a degree of subjectivity, with often more than one method being a valid allocation method. However, it is widely accepted that these expenses are customer-related. Customer service and information expenses (Accounts 906 through 910) include costs associated with encouraging safe and efficient use of the utility's service and responding to customer inquiries.[50] Sales Expenses (Account 911 through 917) are

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[47] Id. at p. ii.
[48] Although the factor names are different, the actual allocation factors are the same for metric.
[49] Elliott P. Tanos, Direct Testimony, Schedule EPT-1.
[50] National Association of Regulatory Utility Commissioners, Electric Utility Cost Allocation Manual, January 1992, p. 103.

costs associated with the advertising of utility services to influence customers.[51] Intuitively, these costs are more associated with the number of customers on the utility's system than the total amount of energy sold to end-use customers.

Q. WHAT DOES THE NARUC MANUAL SAY ABOUT THESE CUSTOMER-RELATED EXPENSES?

A. While the NARUC Manual is admittedly not prescriptive, it does offer some rather definitive guidelines on the allocation of these types of costs by noting that:

> The usual approach in functionalizing customer accounts, customer service and the expense of information and sales is to assign these expenses to the distribution function and classify them as customer-related.
>
> ...
>
> Where these accounts have been assigned to the distribution function and classified as customer-related, care must be taken in developing the proper allocators. Even with detailed records, cost directly assigned to the various customer classes may be very cumbersome and time consuming. Therefore, an allocation factor based upon the number of customers or the number of meters may be appropriate if weighting factors are applied to reflect differences in the cost of reading residential, commercial, and industrial meters.[52]

Q. WHAT IS YOUR RECOMMENDATION REGARDING THE ALLOCATION OF CUSTOMER SERVICE, INFORMATION, AND SALES EXPENSES (ACCOUNTS 906 THROUGH 917)?

A. I recommend the Commission adopt a customer-based allocation factor given the nature of the costs and the fact that the use of a customer-based allocation factor for these costs is generally more consistent with traditional cost of service modeling.

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[51] Id. at pp. 103-104.
[52] Id. at pp. 102-103.

D. CCOSS RECOMMENDATIONS

Q. DO YOUR CCOSS RECOMMENDATIONS CHANGE THE CLASS RATES OF RETURN?

A. Yes. I have identified those changed class rates of return and compared them to the Company's original CCOSS results in Schedule DED-10. I have also prepared an alternative CCOSS using my recommended allocation factors, which is attached to this direct testimony as Schedule DED-11. For comparison purposes, results of the Company's CCOSS are additionally shown within Schedule DED-12.

Q. WOULD YOU PLEASE SUMMARIZE YOUR CCOSS RECOMMENDATIONS?

A. Yes. I recommend that the Commission adopt the Company's proposed CCOSS with the modifications of using a Total Distribution Plant allocator to allocate general and common plant accounts, using a 100 percent number of customers to allocate Customer Service and Information Expense (Accounts 907 through 910), and using a 100 percent number of customers to allocate Sales Expense (Accounts 912 and 913).

IV. RATE DESIGN

A. RATE DESIGN OBJECTIVES

Q. WHAT ARE SOME OF THE GUIDING CRITERIA OR PRINCIPLES UPON WHICH RATE DESIGN SHOULD BE BASED?

A. There are several generally-accepted rate design principles used in utility regulation that include:

- Rates should be fair, just, and reasonable, and not unduly discriminatory.

- To the extent possible, gradualism should be used to protect customers from rate shock.
- Rate continuity should be maintained.
- Rates should be informed by costs, but class cost of service results need not be the only factor used in rate development.
- Rates should be understandable to customers.

Q. HOW ARE THE ABOVE CRITERIA BLENDED TO DEVELOP RATES FOR A REGULATED UTILITY?

A. While it is important to consider all of the earlier-mentioned principles, any principle's relative weight can change depending upon the importance of certain policy goals. Rate design should strike a balance between policy goals and result in rates that are fair, just, and reasonable. Because there is no pre-set universally-accepted formula for developing rates, judgment is often necessary in formulating a rate design that meets these objectives.

Q. HAS THE COMMISSION COME TO SIMILAR RATE DESIGN CONCLUSIONS?

A. Yes. In designing rates in Delmarva's 2005 rate case, the Commission emphasized gradualism because customers were "to experience substantial rate shock as a result of the implementation of supply rates" at the same time new base rates were to go into effect.[53]

Q. HAVE YOU REVIEWED THE COMMISSION'S ORDERS IN THE LAST THREE DELMARVA RATE CASES?

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[53] In the Matter of the Application of Delmarva Power & Light Company for Approval of a Change in Electric Distribution Base Rates and Miscellaneous Tariff Changes (Filed September 1, 2005), Docket No. 05-304, Order No. 6930 (September 1, 2005) at p. 145.

A. Yes. The Company's last three rate cases date back to 2005 and include Docket No. 05-304 (2005), Docket No. 09-414 (2009), and Docket No. 11-528 (2011).

Q. CAN YOU EXPLAIN THE COMMISSION'S RATE DESIGN AND REVENUE DISTRIBUTION FINDINGS IN THE LAST TWO RATE CASES?

A. Yes. The Company's two most recent rate cases were settled by stipulation. In both cases, the Commission approved a stipulation among the parties that resulted in the distribution of the approved revenue increase to all classes except the Transportation class on an equal percentage basis.[54]

Q. WHAT REVENUE DISTRIBUTION METHODOLOGY WAS APPROVED BY THE COMMISSION IN DELMARVA'S 2005 RATE CASE?

A. In the Company's 2005 rate case (Docket No. 05-304), the Commission approved Staff's revenue distribution methodology, which allocated the approved revenue decrease in two steps. First, specific class revenue goals were determined for the classes targeted to receive rate increases to move them closer to their required class returns. Second, the remaining classes received decreases and these were determined by "scaling back Delmarva's claimed cost-based class revenue requirements for those service classifications proportionately to derive Staff's recommended base rate reduction."[55]

Q. HOW WERE THE RATES DESIGNED IN THE COMPANY'S LAST THREE RATE CASES?

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[54] In the Matter of the Application of Delmarva Power & Light Company for an Increase in Electric Base Rates and Miscellaneous Tariff Changes (Filed September 18, 2009), Docket No. 09-414, Order No. 7897 (January 18, 2011) at Exhibit A, pp. 4-5; In the Matter of the Application of Delmarva Power & Light Company for an Increase in Electric Base Rates and Miscellaneous Tariff Changes (Filed December 2, 2011), Docket No. 11-528, Order No. 8265 (December 18, 2012) at p. 30.

[55] Delmarva Power, Docket No. 05-304, Order No. 6930, supra at pp. 138-139.

A. There is no discussion on how rates were designed in the settlement agreements in the last two rate cases (Docket Nos. 09-414 and 11-528). However, the Commission adopted Staff's rate design proposal in Delmarva's 2005 rate case (Docket No. 05-304). Customer charges were set at a level halfway between a customer's current customer charge and Delmarva's proposed customer charge in order "to move the customer charges toward cost of service while simultaneously limiting the intra-class rate impacts that would otherwise result from Delmarva's proposed rate design."[56] For classes with demand charges, the residual revenue class revenue requirement was assigned to the demand charges in a constrained manner so that no class' demand charge would be increased. Any remaining revenue requirement was assigned to the energy charges.

Q. TURNING TO THE CASE AT HAND, CAN YOU SUMMARIZE THE COMPANY'S RATE DESIGN GOALS?

A. Yes. The Company's primary guiding principle to support its rate design is cost causation. The Company's position is that rates that accurately reflect underlying costs provide a greater degree of fairness.[57] Delmarva uses class relative rates of return to evaluate the degree to which its rate design accurately reflects underlying costs.[58] In considering the amount of revenue to allocate to a class, the Company states it takes into consideration customer impacts:

> Movement of all service classification URORs [Unitized Rates of Return] to 1.0 in a single rate change may require significant shifts in allocation of revenue requirements between service classifications and, consequently, could have large inter-class rate impacts. Therefore, customer impact

[56] Delmarva Power, Docket No. 05-304, Order No. 6930, supra at p. 139.
[57] Marlene C. Santacecilia, Direct Testimony, 2:23 and 3:1-4.
[58] Id. at 3:7-15.

should be considered as a balancing factor in any effort to achieve the goal of setting all service classification URORs at unity.[59]

B. REVENUE DISTRIBUTION

Q. PLEASE DISCUSS THE COMPANY'S PROPOSED REVENUE DISTRIBUTION.

A. The Company follows a two-step process. In the first step, the Company's goal is to move each class rate of return toward or within a "reasonable band" (0.90 to 1.10) of the overall system of average rate of return.[60] In the second step, the remaining revenue increase is allocated to all rate classes equally[61] based on their current distribution revenue as a percent of the total distribution revenue.[62] The Company limits the increase of any one service classification to 1.5 times the overall percentage increase.[63]

Q. CAN YOU PLEASE EXPLAIN WHAT YOU MEAN BY A RELATIVE RATE OF RETURN?

A. Yes. A "relative rate of return" is simply the ratio of a given class' estimated rate of return to the overall system rate of return. For example, if the residential class is estimated to be earning 11 percent from the CCOSS, and the Company is requesting a 10 percent overall rate of return, then the residential class can be said to have a "relative rate of return" of 1.10 (i.e., 11 percent divided by 10 percent). Relative rates of return can also be thought of as a special type of index number measuring a specific class' return relative to the Company's overall rate of return. Thus, a class with a

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[59] Id. at 3:20-23 and 4:1-2.
[60] Id. at 4:5-7.
[61] Id. at 4:7-8.
[62] Company's Response to Data Request AG-RD-25.
[63] Marlene C. Santacecilia, Direct Testimony, 4:8-10.

relative rate of return greater than 1.0 means that the class is estimated to be earning at a percent greater than the Company's overall rate of return, and one with a relative return below 1.0 can be said to be earning an amount less than the Company's overall rate of return. Schedule DED-10 presents the Company's estimated class relative rates of return under its current and proposed rates.

Q. WOULD YOU PLEASE SUMMARIZE HOW THE COMPANY'S REVENUE INCREASE WAS DISTRIBUTED IN ITS LAST THREE RATE CASES?

A. The last two rate cases (Docket Nos. 11-528 and 09-414) ended in settlement whereby the authorized revenue increase was distributed on an across-the-board basis, i.e., the percentage change in distribution revenues was the same for each class, except class General Service Transmission (GS-T), which did not receive any of the increase.[64] In the preceding case (05-304), the Commission approved the Hearing Examiner's finding that the Staff's allocation methodology should be adopted over the Company's proposal for several reasons.[65] First, Staff placed more emphasis on gradualism than the Company because a large supply-side rate increase was taking place concurrently with the culmination of the rate case. The Hearing Examiner in that proceeding found it appropriate to avoid rate shock.[66] Second, Staff's methodology did not result in situations where customers within a class were proposed to receive a rate increase when the class as a whole received a rate decrease.[67]

Q. WHAT IS THE IMPACT ON THE RESIDENTIAL CLASS WITH THE COMPANY'S PROPOSED REVENUE DISTRIBUTION?

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[64] Delmarva Power, Docket No. 11-528, Order No. 8265, supra, at p. 30.
[65] Delmarva Power, Docket No. 05-304, Order No. 6930, supra at ¶298.
[66] Id. at ¶287.
[67] Id. at ¶290.

A. The Company's revenue distribution proposal results in an increase in rates of 21 percent for Residential and almost 35 percent for Residential Space Heating.[68] The Company's revenue distribution proposal results in allocating almost 65 percent of the revenue requirement to the residential classes.

Q. WHAT ARE YOUR REVENUE DISTRIBUTION RECOMMENDATIONS?

A. I recommend a two-step revenue distribution that limits the rate increase to any under-earning class in the first step and distributes any remaining revenue deficiency across all other classes in proportion to their test year revenue in the second step. My approach is consistent with the settlement approved in the last rate case, which consisted of a two-step approach, and with the overall allocation of the proposed rate increase to under-earning classes. My proposed increase to these under-earning classes is tempered, however, by allocating some share of the proposed rate increase to the over-earning classes. The results of my recommended revenue distribution are shown on Schedule DED-13.

C. CUSTOMER CHARGES

Q. HOW DO THE COMPANY'S RESIDENTIAL CUSTOMER CHARGE REVENUES COMPARE WITH THE RESULTS OF ITS CLASS COST OF SERVICE STUDY?

A. The customer charge revenue associated with the Residential class, including Residential-Time of Use customers, has been provided, along with customer charge revenue recoveries for the other customer classes, in Schedule DED-14.

Q. WOULD YOU PLEASE DISCUSS THE COMPANY'S CUSTOMER CHARGE PROPOSALS?

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[68] Marlene C. Santacecilia, Direct Testimony, Schedule (MCS)-1.

A. Yes. A summary of the Company's current and proposed customer charges has been provided in Schedule DED-15. The Company is proposing to maintain its current rate structure with a delivery charge and a customer charge. The proposed customer charges were determined by moving current charges towards the level of customer-related costs, with a limitation of a 50 percent increase.[69]

Q. WHAT IS THE IMPACT OF THE COMPANY'S RECOMMENDATION ON THE RESIDENTIAL CLASSES?

A. The Company proposes to increase the customer charge for the Residential and Residential Space Heating classes by close to 50 percent, and the Residential-Time of Use class by 42 percent. The Company proposes to increase customer charges for the Small General Service by 18 percent. The customer charge increases for the remaining classes range from no change for the Large General Service-Secondary class to 101 percent for the General Service Primary class.

Q. HOW DO THE COMPANY'S PROPOSED RESIDENTIAL CUSTOMER CHARGES COMPARE TO OTHER ELECTRIC DISTRIBUTION COMPANIES?

A. Schedule DED-16 provides a survey of current residential and small commercial customer charges for major electric distribution companies operating in the Atlantic region.[70] The Company's proposed Residential customer charge of $13.98 per month is higher than the average residential system charge of $9.33 for the surveyed Atlantic region utilities. Six electric distribution utilities in the survey have residential customer charges greater than the Company's proposal, and 16 companies have a customer

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[69] Company's Response to Data Request AG-RD-44.

[70] The Atlantic region includes New York, Pennsylvania, New Jersey, Maryland, Delaware, District of Columbia, West Virginia, North Carolina, South Carolina, Virginia, Georgia, and Florida as defined by the U.S. Census Bureau.

charge less than the Company's proposal. Delmarva's proposed residential system charge is higher than 73 percent of the utility companies included in the survey.

Q. WHAT ABOUT THE SMALL COMMERCIAL CUSTOMER CHARGES?

A. The Company's proposed small commercial customer charge of $12.54 per month is lower than the average small commercial customer charge of $13.82 for other regional utilities. Twelve out of 22 electric distribution companies (55 percent) in the survey referenced earlier have customer charges lower than the Company.

Q. HOW SHOULD POLICY BALANCE RATE DESIGN GOALS BETWEEN SETTING APPROPRIATE CUSTOMER CHARGES AND VOLUMETRIC RATES?

A. Modern utility pricing theory is primarily concerned with the development of optimal tariff design, which over the years has become dominated by a form of pricing referred to as a "two-part tariff," sometimes referred to more technically as a non-linear (or non-uniform) pricing approach. Once a class revenue requirement is established, the goal for regulators should be one that sets the most appropriate rates based upon various efficiency and equity considerations. Balancing the weight of how costs are recovered between fixed rates, variable rates, block rates, and seasonal rates are all integrated parts of that process.

Q. WHAT IS THE APPROPRIATE ROLE OF COSTS IN SETTING RATES BASED UPON A TWO-PART TARIFF?

A. Costs can be instructive in establishing a baseline upon which prices may be set, but costs need not serve as the sole or exclusive basis for rates in order for them to be set optimally (i.e., fixed charges need not strictly equal fixed costs, variable rates need not strictly equal variable costs). Unfortunately, the "fixed charge-equals-fixed

cost" dogma gets repeated so often that it can often drown out meaningful discussions about other equally important considerations in setting rates in imperfect markets. In fact, appropriate rate setting in the context of a two-part tariff typically has more to do with consumer demand than it does with cost.

Q. DID YOU PREPARE AN ANALYSIS OF COSTS COMMONLY ASSOCIATED WITH SYSTEM OR CUSTOMER CHARGES?

A. Yes, and that has been provided in Schedule DED-17. "Customer-related" expense accounts are those typically allocated on the basis of customers and include: removing and setting meters; maintenance of meters; services expense; maintenance of services; meter reading expense; customer records and collections; customer billing and accounting; customer service and information; and sales expense. These costs can also include the depreciation expense associated with the services and meter plant accounts and property taxes as well as the carrying charges (at the Company's requested rate of return) for the customer portion of services investment and 100 percent of the meters investment.

Q. WHAT DO THE RESULTS OF YOUR ANALYSIS SHOW?

A. In most cases, the Company's current customer charges are insufficient to recover commonly-recognized customer costs. The Residential classes' customer-related costs are $15.64 compared to the current customer charge revenue per customer of $9.34. The Small General Service class[71] is estimated to have customer-related costs at $26.71 compared to its current system charge revenue per customer of $19.42.

[71] In the CCOSS, the Small General Service class is combined with Small General Service-Water Heating, Small General Service-Space Heating, and Medium General Service classes.

Q. WHAT ARE YOUR CUSTOMER CHARGE RECOMMENDATIONS?

A. My specific customer charge recommendations are provided on Schedule DED-15. My recommended customer charges move classes currently recovering revenues that are lower than their customer-related costs towards their full costs of service. This increase, however, is capped to a level that is identical to the limitation applied in the first step of my revenue distribution.

D. VOLUMETRIC CHARGES

Q. WOULD YOU PLEASE EXPLAIN THE COMPANY'S VOLUMETRIC DISTRIBUTION RATE PROPOSALS?

A. Yes. For most classes, the Company proposes to recover the remaining portion of a class' revenue requirement through the energy charges. However, for those classes that also have a demand charge, the entire remainder of the class' revenue increase is recovered through the demand charge, with no part flowing through the energy charge.[72]

Q. WHAT ARE YOUR VOLUMETRIC RATE RECOMMENDATIONS?

A. My volumetric rate recommendations differ from those offered by the Company. These differences are a function of my alternative CCOSS, the resulting alternative revenue distribution, my recommended customer charges, and the treatment of demand charges. My customer charge recommendations assess class-specific, customer-related costs to each recommended class-specific customer charge. Costs not recovered through the customer charge are recovered through volumetric charges. For those classes that have a Demand Charge and a Delivery Service Rate, I retain the existing relationship between the demand charge and the delivery rate and

[72] Marlene C. Santacecilia, Direct Testimony, (MCS)-1.

recommend allocating the increase on an equal percentage basis between the two components. My alternative rates based upon my alternative CCOSS and recommended revenue distribution are provided in Schedule DED-15.

E. RATE DESIGN RECOMMENDATIONS

Q. WOULD YOU PLEASE SUMMARIZE YOUR RATE DESIGN RECOMMENDATIONS?

A. Yes. My rate design recommendations can be summarized as follows:

- Revenue responsibilities for developing rates should be allocated using a two-step methodology. The first step limits the rate increase to any under-earning class, and the second step distributes any remaining revenue deficiency across all other classes in proportion to their test year revenue.
- Existing customer charges should be increased for those classes where their current revenues are less than their customer-related costs to a level that moves towards their full cost of service.
- After developing the customer charges, the remaining costs are recovered through volumetric charges. For those classes that have a Demand Charge and a Delivery Service Rate, I recommend allocating the increase on an equal percentage basis between the demand charge and the delivery rate to maintain the existing relationship between the two components.

Q. DOES THIS COMPLETE YOUR TESTIMONY PREFILED ON AUGUST 16, 2013?

A. Yes, it does.

Attachment A

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EDUCATION

Ph.D., Economics, Florida State University, 1995.
M.S., Economics, Florida State University, 1992.
M.S., International Affairs, Florida State University, 1988.
B.A., History, University of West Florida, 1987.
A.A., Liberal Arts, Pensacola State College, 1985.

Master's Thesis: *Nuclear Power Project Disallowances: A Discrete Choice Model of Regulatory Decisions*

Ph.D. Dissertation: *An Empirical Examination of Environmental Externalities and the Least-Cost Selection of Electric Generation Facilities*

ACADEMIC APPOINTMENTS

Louisiana State University, Baton Rouge, Louisiana

Center for Energy Studies

2007-Current	Director, Division of Policy Analysis
2006-Current	Professor
2003-Current	Associate Executive Director
2001-2006	Associate Professor
2000-2001	Research Fellow and Adjunct Assistant Professor
1995-2000	Assistant Professor

School of the Coast and the Environment (Department of Environmental Studies)

2010-Current	Adjunct Professor

E.J. Ourso College of Business Administration (Department of Economics)

2006-Current	Adjunct Professor
2001-2006	Adjunct Associate Professor
1999-2000	Adjunct Assistant Professor

Florida State University, Tallahassee, Florida

College of Social Sciences, Department of Economics

1995 Instructor

PROFESSIONAL EXPERIENCE

Acadian Consulting Group, Baton Rouge, Louisiana

2001-Current Consulting Economist/Principal
1995-2000 Consulting Economist/Principal

Econ One Research, Inc., Houston, Texas

2000-2001 Senior Economist

Florida Public Service Commission, Tallahassee, Florida
Division of Communications, Policy Analysis Section

1995 Planning & Research Economist

Division of Auditing & Financial Analysis, Forecasting Section

1993 Planning & Research Economist
1992-1993 Economist

Project for an Energy Efficient Florida &
Florida Solar Energy Industries Association, Tallahassee, Florida

1994 Energy Economist

Ben Johnson Associates, Inc., Tallahassee, Florida

1991-1992 Research Associate
1989-1991 Senior Research Analyst
1988-1989 Research Analyst

GOVERNMENT APPOINTMENTS

2007-Current Louisiana Representative, Interstate Oil and Gas Compact Commission; Energy Resources, Research & Technology Committee.

2007-Current Louisiana Representative, University Advisory Board Representative; Energy Council (Center for Energy, Environmental and Legislative Research).

2005	Member, Task Force on Energy Sector Workforce and Economic Development (HCR 322).
2003-2005	Member, Energy and Basic Industries Task Force, Louisiana Economic Development Council
2001-2003	Member, Louisiana Comprehensive Energy Policy Commission.

PUBLICATIONS: BOOKS AND MONOGRAPHS

1. *Power System Operations and Planning in a Competitive Market.* (2002). With Fred I. Denny. New York: CRC Press.

2. *Distributed Energy Resources: A Practical Guide for Service.* (2000). With Ritchie Priddy. London: Financial Times Energy.

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4. "Using Competitive Bidding As A Means of Securing the Best of Competitive and Regulated Worlds." (2004). With Tom Ballinger and Elizabeth A. Downer. *NRRI Journal of Applied Regulation*. 2 (November): 69-85. (*Received 2005 Best Paper Award by NRRI*)

5. "Deregulation of Generating Assets and the Disposition of Excess Deferred Federal Income Taxes." (2004). With K.E. Hughes II. *International Energy Law and Taxation Review*. 10 (October): 206-212.

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7. "A is for Access: A Definitional Tour Through Today's Energy Vocabulary." (2001) *Public Resources Law Digest*. 38: 2.

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9. "Modeling Regional Power Markets and Market Power." (2001). With Robert F. Cope. *Managerial and Decision Economics.* 22:411-429.

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11. "Cogeneration and Electric Power Industry Restructuring" (1999). With Andrew N. Kleit. *Resource and Energy Economics.* 21:153-166.

12. "Capacity and Economies of Scale in Electric Power Transmission" (1999). With Robert F. Cope and Dmitry Mesyanzhinov. *Utilities Policy* 7: 155-162.

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PUBLICATIONS: PEER REVIEWED PROCEEDINGS

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4. "Power System Operations, Control, and Environmental Protection in a Restructured Electric Power Industry" (1998). With Fred I. Denny. *IEEE Proceedings: Large Engineering Systems Conference on Power Engineering.* June: 294-298.

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PUBLICATIONS: OTHER SCHOLARLY PROCEEDINGS

1. "A Collaborative Investigation of Baseline and Scenario Information for Environmental Impact Statements" (2005). *Proceedings of the 23rd Annual Information Technology Meetings.* U.S. Department of the Interior, Minerals Management Service, Gulf Coast Region, New Orleans, LA. January 12, 2005.

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4. "The Role of ANS Gas on Southcentral Alaskan Development." (2002). With William Nebesky and Dmitry Mesyanzhinov. *Proceedings of the International Association for Energy Economics: Energy Markets in Turmoil: Making Sense of It All.* October.

5. "A New Consistent Approach to Modeling Regional Economic Impacts of Offshore Oil and Gas Activities." (2002). With Vicki Zatarain. *Proceedings of the 2002 National IMPLAN Users Conference*: 241-258.

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8. "The IRS' Latest Proposal on Tax Normalization: A Pyrrhic Victory for Ratepayers," (2006). With K.E. Hughes II. *Oil, Gas and Energy Quarterly*. 55(1): 217-236

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19. "Will Competitive Bidding Make a Comeback?" (2004). With K.E. Hughes II. *Oil, Gas and Energy Quarterly*. 52: 659-674

20. "An Electric Utility's Exposure to Future Environmental Costs: Does It Matter? You Bet!" (2003). With K.E. Hughes II. *Oil, Gas and Energy Quarterly*. 52: 457-469.

21. "White Paper or White Flag: Do FERC's Concessions Represent A Withdrawal from Wholesale Power Market Reform?" (2003). With K.E. Hughes II. *Oil, Gas and Energy Quarterly*. 52: 197-207.

22. "Clear Skies" or Storm Clouds Ahead? The Continuing Debate over Air Pollution and Climate Change" (2003). With K.E. Hughes II. *Oil, Gas and Energy Quarterly*. 51: 823-848.

23. "Economic Displacement Opportunities in Southeastern Power Markets." (2003). With Dmitry V. Mesyanzhinov. *USAEE Dialogue*. 11: 20-24.

24. "What's Happened to the Merchant Energy Industry? Issues, Challenges, and Outlook" (2003). With K.E. Hughes II. *Oil, Gas and Energy Quarterly*. 51: 635-652.

25. "Is There a Role for the TVA in Post-Restructured Electric Markets?" (2002). With K.E. Hughes II. *Oil, Gas and Energy Quarterly*. 51: 433-454.

26. "The Role of Alaska North Slope Gas in the Southcentral Alaska Regional Energy Balance." (2002). With William Nebesky and Dmitry Mesyanzhinov. *Natural Gas Journal*. 19: 10-15.

27. "Standardizing Wholesale Markets For Energy." (2002). With K.E. Hughes II. *Oil, Gas and Energy Quarterly*. 51: 207-225.

28. "Do Economic Activities Create Different Economic Impacts to Communities Surrounding the Gulf OCS?" (2002). With Williams O. Olatubi. *IAEE Newsletter*. Second Quarter: 16-20.

29. "Will Electric Restructuring Ever Get Back on Track? Texas is not California." (2002). With K.E. Hughes II. *Oil, Gas and Energy Quarterly*. 50: 943-960.

30. "An Assessment of the Role and Importance of Power Marketers." (2002). With K.E. Hughes II. *Oil, Gas and Energy Quarterly. 50: 713-731.*

31. "The EPA v. The TVA, et. al. Over New Source Review." (2001) With K.E. Hughes, II. *Oil, Gas and Energy Quarterly*. 50:531-543.

32. "Energy Policy by Crisis: Proposed Federal Changes for the Electric Power Industry." (2001). With K.E. Hughes II. *Oil, Gas and Energy Quarterly*. 50:235-249.

33. "A is for Access: A Definitional Tour Through Today's Energy Vocabulary." (2001). With K.E. Hughes II. *Oil, Gas and Energy Quarterly*. 49:947-973.

34. "California Dreaming: Are Competitive Markets Achievable?" (2001). With K.E. Hughes II. *Oil, Gas and Energy Quarterly*. 49: 743-759.

35. "Distributed Energy Must Be Watched As Opportunity for Gas Companies." (2001). With Martin Collette, and Ritchie D. Priddy. *Natural Gas Journal*. January: 9-16.

36. "Clean Air, Kyoto, and the Boy Who Cried Wolf." (2000). With K.E. Hughes II. *Oil, Gas and Energy Quarterly*. December: 529-540.

37. "Energy Conservation Programs and Electric Restructuring: Is There a Conflict?" (2000). With K.E. Hughes II. *Oil, Gas and Energy Quarterly*. September: 211-224.

38. "The Post-Restructuring Consolidation of Nuclear-Power Generation in the Electric Power Industry." (2000) With K.E. Hughes II. *Oil, Gas and Energy Quarterly*. 49: 751-765.

39. "Issues and Opportunities for Small Scale Electricity Production in the Oil Patch." (2000). With Ritchie D. Priddy. *American Oil and Gas Reporter*. 49: 78-82.

40. "Distributed Energy Resources: The Next Paradigm Shift in the Electric Power Industry."

(2000). With K.E. Hughes II *Oil, Gas and Energy Quarterly*. 48:593-602.

41. "Coming to a Neighborhood Near You: The Merchant Electric Power Plant." (1999). With K.E. Hughes II. *Oil, Gas, and Energy Quarterly*. 48:433-441.

42. "Slow as Molasses: The Political Economy of Electric Restructuring in the South." (1999). With K.E. Hughes II. *Oil, Gas, and Energy Quarterly*. 48: 163-183.

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44. "Reliability or Profit? Why Entergy Quit the Southwest Power Pool." (1998). With Fred I. Denny. *Public Utilities Fortnightly*. February 1: 30-33.

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6. *Fact Book: Offshore Oil and Gas Industry Support Sectors*. (2010). U.S. Department of the Interior, Bureau of Ocean Energy Management, Gulf of Mexico Region, New Orleans, LA. OCS Study BOEM 2010-042. 138pp.

7. *The Impacts of Greenhouse Gas Regulation on the Louisiana Economy*. (2011). With Michael D. McDaniel, Christopher Peters, Kathryn R. Perry, and Lauren L. Stuart. Louisiana Greenhouse Gas Inventory Project, Task 3 and 4 Report. Prepared for the Louisiana Department of Economic Development. Baton Rouge, LA: LSU Center for Energy Studies, 134 pp.

8. *Overview of States' Climate Action and/or Alternative Energy Policy Measures*. (2010). With Michael D. McDaniel, Christopher Peters, Kathryn R. Perry, and Lauren L. Stuart. Louisiana Greenhouse Gas Inventory Project, Task 2 Report. Prepared for the Louisiana Department of Economic Development. Baton Rouge, LA: LSU Center for Energy Studies, 30 pp.

9. *Louisiana Greenhouse Gas Inventory*. (2010). With Michael D. McDaniel, Christopher Peters, Kathryn R. Perry, Lauren L. Stuart, and Jordan L. Gilmore. Louisiana Greenhouse Gas Inventory Project, Task 1 Report. Prepared for the Louisiana Department of Economic Development. Baton Rouge, LA: LSU Center for Energy Studies, 114 pp.

10. *The Benefits of Continued and Expanded Investments in the Port of Venice*. (2009). With Christopher Peters and Kathryn Perry. Baton Rouge, LA: LSU Center for Energy Studies. 83 pp.

11. *Examination of the Development of Liquefied Natural Gas on the Gulf of Mexico*. (2008). U.S. Department of the Interior, Minerals Management Service, Gulf of Mexico OCS Region, New Orleans, LA OCS Study MMS 2008-017. 106 pp.

12. *Gulf of Mexico OCS Oil and Gas Scenario Examination: Onshore Waste Disposal*. (2007). With Michelle Barnett, Derek Vitrano, and Kristen Strellec. OCS Report, MMS 2007-051. New Orleans, LA: U.S. Department of the Interior, Minerals Management Service, Gulf of Mexico Region.

13. *Economic Impact Analysis of the Proposed Lake Charles Gasification Project*. (2007). Report Prepared on Behalf of Leucadia Corporation.

14. *The Economic Impacts of New Jersey's Proposed Renewable Portfolio Standard*. (2005) Report Prepared on Behalf of the New Jersey Division of Ratepayer Advocate.

15. *The Importance of Energy Production and Infrastructure in Plaquemines Parish*. (2006). Report Prepared on Behalf of Project Rebuild Plaquemines.

16. *Louisiana's Oil and Gas Industry: A Study of the Recent Deterioration in State Drilling Activity*. (2005). With Kristi A.R. Darby, Jeffrey M. Burke, and Robert H. Baumann. Baton Rouge, LA: Louisiana Department of Natural Resources.

17. *Comparison of Methods for Estimating the NO_x Emission Impacts of Energy Efficiency and Renewable Energy Projects Shreveport, Louisiana Case Study*. (2005). With Adam Chambers, David Kline, Laura Vimmerstedt, Art Diem, and Dmitry Mesyanzhinov. Golden, Colorado: National Renewable Energy Laboratory.

18. *Economic Opportunities for a Limited Industrial Retail Choice Plan in Louisiana*. (2004). With Elizabeth A. Downer and Dmitry V. Mesyanzhinov. Baton Rouge, LA: Louisiana State University Center for Energy Studies.

19. *Economic Opportunities for LNG Development in Louisiana*. (2004). With Elizabeth A. Downer and Dmitry V. Mesyanzhinov. Baton Rouge, LA: Louisiana Department of Economic Development and Greater New Orleans, Inc.

20. *Marginal Oil and Gas Production in Louisiana: An Empirical Examination of State Activities and Policy Mechanisms for Stimulating Additional Production.* (2004). With Dmitry V. Mesyanzhinov, Jeffrey M. Burke, Robert H. Baumann. Baton Rouge, LA: Louisiana Department of Natural Resources, Office of Mineral Resources.

21. *Deepwater Program: OCS-Related Infrastructure in the Gulf of Mexico Fact Book.* (2004). With Louis Berger Associates, University of New Orleans National Ports and Waterways Institute, and Research and Planning Associates. MMS Study No. 1435-01-99-CT-30955. U.S. Department of the Interior, Minerals Management Service.

22. *The Power of Generation: The Ongoing Benefits of Independent Power Development in Louisiana.* With Dmitry V. Mesyanzhinov, Jeffrey M. Burke, and Elizabeth A. Downer. Baton Rouge, LA: LSU Center for Energy Studies, 2003.

23. *Modeling the Economic Impact of Offshore Oil and Gas Activities in the Gulf of Mexico: Methods and Application.* (2003). With Williams O. Olatubi, Dmitry V. Mesyanzhinov, and Allan G. Pulsipher. Prepared by the Center for Energy Studies, Louisiana State University, Baton Rouge, LA. OCS Study MMS2000-0XX. U.S. Department of the Interior, Minerals Management Service, Gulf of Mexico OCS Region, New Orleans, LA.

24. *An Analysis of the Economic Impacts Associated with Oil and Gas Activities on State Leases.* (2002) With Robert H. Baumann, Dmitry V. Mesyanzhinov, and Allan G. Pulsipher. Baton Rouge, LA: Louisiana Department of Natural Resources, Office of Mineral Resources.

25. *Alaska In-State Natural Gas Demand Study.* (2002). With Dmitry Mesyanzhinov, et.al. Anchorage, Alaska: Alaska Department of Natural Resources, Division of Oil and Gas.

26. *Moving to the Front of the Lines: The Economic Impacts of Independent Power Plant Development in Louisiana.* (2001). With Dmitry Mesyanzhinov and Williams O. Olatubi. Baton Rouge, LA: Louisiana State University, Center for Energy Studies.

27. *The Economic Impacts of Merchant Power Plant Development in Mississippi.* (2001). Report Prepared on Behalf of the US Oil and Gas Association, Alabama and Mississippi Division. Houston, TX: Econ One Research, Inc.

28. *Energy Conservation and Electric Restructuring In Louisiana.* (2000). With Dmitry Mesyanzhinov, Ritchie D. Priddy, Robert F. Cope III, and Vera Tabakova. Baton Rouge, LA: Louisiana State University, Center for Energy Studies.

29. *Assessing the Environmental and Safety Risks of the Expanded Role of Independents in Oil and Gas E&P Operations on the U.S. Gulf of Mexico OCS.* (1996). With Allan Pulsipher, Omowumi Iledare, Dmitry Mesyanzhinov, William Daniel, and Bob Baumann. Baton Rouge, LA: Louisiana State University, Center for Energy Studies.

30. *Restructuring the Electric Utility Industry: Implications for Louisiana.* (1996). With Allan Pulsipher and Kimberly H. Dismukes. Baton Rouge, LA: Louisiana State University, Center for Energy Studies.

GRANT RESEARCH

1. *Principal Investigator.* "Analysis of the Potential for Combined Heat and Power (CHP) in Louisiana. (2013). Louisiana Department of Natural Resources. Total Project: $90,000. Status: In Progress.

2. *Co-Principal Investigator.* "CNH: A Tale of Two Louisianas: Coupled Natural-Human Dynamics in a Vulnerable Coastal System" (2013) With Nina Lam, Margaret Reams, Kam-Biu Liu, Victor Rivera, and Kelley Pace. National Science Foundation. Total Project: $1.5 million. Status: In Progress (Sept 2012-Feb 2017).

3. *Principal Investigator.* "Examination of Unconventional Natural Gas and Industrial Economic Development" (2012). America's Natural Gas Alliance. Total Project: $48,210. Status: Completed.

4. *Principal Investigator.* "Investigation of the Potential Economic Impacts Associated with Shell's Proposed Gas-To-Liquids Project" (2012). Shell Oil Company, North America. Total Project: $76,708. Status: Completed.

5. *Principal Investigator.* "Analysis of the Federal Wind Energy Production Tax Credit." American Energy Alliance. Total Project: $20,000. Status: Completed.

6. *Principal Investigator.* "Energy Sector Impacts Associated with the Deepwater Horizon Oil Spill." Louisiana Department of Economic Development. Total Project: Open. Status: Completed.

7. *Principal Investigator.* "Economic Contributions and Benefits Support by the Port of Venice." Port of Venice Coalition. Total Project: $20,000. Status: Completed.

8. *Principal Investigator.* "Energy Policy Development in Louisiana." Louisiana Department of Natural Resources. Total Project: $150,000. Status: Completed.

9. *Principal Investigator.* "Preparing Louisiana for the Possible Federal Regulation of Greenhouse Gas Regulation." With Michael D. McDaniel. Louisiana Department of Economic Development. Total Project: $98,543. Status: Completed.

10. *Principal Investigator.* "OCS Studies Review: Louisiana and Texas Oil and Gas Activity and Production Forecast; Pipeline Position Paper; and Geographical Units for Observing and Modeling Socioeconomic Impact of Offshore Activity." (2008). With Mark J. Kaiser and Allan G. Pulsipher. U.S. Department of the Interior, Minerals Management Service. Total Project: $377,917 (3 years). Status: Completed.

11. *Principal Investigator.* "State and Local Level Fiscal Effects of the Offshore Petroleum Industry." (2007). With Loren C. Scott. U.S. Department of the Interior, Minerals Management Service. Total Project: $241,216 (2.5 years). Status: Awarded, In Progress.

12. *Principal Investigator.* "Understanding Current and Projected Gulf OCS Labor and Ports

Needs." (2007). With Allan. G. Pulsipher, Kristi A. R. Darby. U.S. Department of the Interior, Minerals Management Service. Total Project: $169,906. (one year). Status: Awarded, In Progress.

13. *Principal Investigator.* "Structural Shifts and Concentration of Regional Economic Activity Supporting GOM Offshore Oil and Gas Activities." (2007). With Allan. G. Pulsipher, Michelle Barnett. U.S. Department of the Interior, Minerals Management Service. Total Project: $78,374 (one year). Status: Awarded, In Progress.

14. *Principal Investigator.* "Plaquemine Parish's Role in Supporting Critical Energy Infrastructure and Production." (2006). With Seth Cureington. Plaquemines Parish Government, Office of the Parish President and Plaquemines Association of Business and Industry. Total Project: $18,267. Status: Completed.

15. *Principal Investigator.* "Diversifying Energy Industry Risk in the Gulf of Mexico." (2006). With Kristi A. R. Darby. U.S. Department of the Interior, Minerals Management Service. Total Project: $65,302 (two years). Status: Awarded, In Progress.

16. *Principal Investigator.* "Post-Hurricane Assessment of OCS-Related Infrastructure and Communities in the Gulf of Mexico Region." (2006). U.S. Department of the Interior, Minerals Management Service. Total Project Funding: $244,837. Status: In Progress.

17. *Principal Investigator.* "Ultra Deepwater Road Mapping Process." (2005). With Kristi A. R. Darby, Subcontract with the Texas A&M University, Department of Petroleum Engineering. Funded by the Gas Technology Institute. Total Project Funding: $15,000. Status: Completed.

18. *Principal Investigator.* "An Examination of the Opportunities for Drilling Incentives on State Leases." (2004). With Robert H. Baumann and Kristi A. R. Darby. Louisiana Office of Mineral Resources. Total Project Funding: $75,000. Status: Completed.

19. *Principal Investigator.* " An Examination on the Development of Liquefied Natural Gas Facilities on the Gulf of Mexico." (2004). With Dmitry V. Mesyanzhinov and Mark J. Kaiser. U.S. Department of the Interior, Minerals Management Service. Total Project Funding $101,054. Status: Completed.

20. *Principal Investigator.* "Examination of the Economic Impacts Associated with Large Customer, Industrial Retail Choice." (2004). With Dmitry V. Mesyanzhinov. Louisiana Mid-Continent Oil and Gas Association. Total Project Funding: $37,000. Status: Completed.

21. *Principal Investigator.* "Economic Opportunities from LNG Development in Louisiana." (2003). With Dmitry V. Mesyanzhinov. Metrovision/New Orleans Chamber of Commerce and the Louisiana Department of Economic Development. Total Project Funding: $25,000. Status: Completed.

22. *Principal Investigator.* "Marginal Oil and Gas Properties on State Leases in Louisiana: An Empirical Examination and Policy Mechanisms for Stimulating Additional Production." (2002). With Robert H. Baumann and Dmitry V. Mesyanzhinov. Louisiana Office of Mineral

Resources. Total Project Funding: $72,000. Status: Completed.

23. *Principal Investigator.* "A Collaborative Investigation of Baseline and Scenario Information for Environmental Impact Statements." (2002). With Dmitry V. Mesyanzhinov and Williams O. Olatubi. U.S. Department of Interior, Minerals Management Service. Total Project Funding: $557,744. Status: Awarded, In Progress.

24. *Co-Principal Investigator.* "An Analysis of the Economic Impacts of Drilling and Production Activities on State Leases." (2002). With Robert H. Baumann, Allan G. Pulsipher, and Dmitry V. Mesyanzhinov. Louisiana Office of Mineral Resources. Total Project Funding: $8,000. Status: Completed.

25. *Principal Investigator.* "Cost Profiles and Cost Functions for Gulf of Mexico Oil and Gas Development Phases for Input Output Modeling." (1998). With Dmitry Mesyanzhinov and Allan G. Pulsipher. U.S. Department of Interior, Minerals Management Service. Total Project Funding: $244,956. Status: Completed.

26. *Principal Investigator.* "An Economic Impact Analysis of OCS Activities on Coastal Louisiana." (1998). With Dmitry Mesyanzhinov and David Hughes. U.S. Department of Interior, Minerals Management Service. Total Project Funding: $190,166. Status: Completed.

27. *Principal Investigator.* "Energy Conservation and Electric Restructuring in Louisiana." (1997). Louisiana Department of Natural Resources." Petroleum Violation Escrow Program Funds. Total Project Funding: $43,169. Status: Completed.

28. *Principal Investigator.* "The Industrial Supply of Electricity: Commercial Generation, Self-Generation, and Industry Restructuring." (1996). With Andrew Kleit. Louisiana Energy Enhancement Program, LSU Office of Research and Development. Total Project Funding: $19,948. Status: Completed.

29. *Co-Principal Investigator.* "Assessing the Environmental and Safety Risks of the Expanded Role of Independents in Oil and Gas E&P Operations on the U.S. Gulf of Mexico OCS." (1996). With Allan Pulsipher, Omowumi Iledare, Dmitry Mesyanzhinov, William Daniel, and Bob Baumann. U.S. Department of Interior, Minerals Management Service, Grant Number 95-0056. Total Project Funding: $109,361. Status: Completed.

ACADEMIC CONFERENCE PAPERS/PRESENTATIONS

1. "Economies of Scale, Learning Curves, and Offshore Wind Development Costs" (2012). With Gregory Upton. Southern Economic Association Annual Conference, New Orleans, LA November 17.

2. "Analysis of Risk and Post-Hurricane Reaction." (2009). 25th Annual Information Transfer Meeting. U.S. Department of the Interior, Minerals Management Service. January 7.

3. "Legacy Litigation, Regulation, and Other Determinants of Interstate Drilling Activity Differentials." (2008). With Christopher Peters and Mark Kaiser. 28th Annual USAEE/IAEE

North American Conference: Unveiling the Future of Future of Energy Frontiers. New Orleans, LA, December 3, 2008.

4. "Gulf Coast Energy Infrastructure Renaissance: Overview." (2008). 28th Annual USAEE/IAEE North American Conference: Unveiling the Future of Future of Energy Frontiers. New Orleans, LA, December 3, 2008.

5. "Understanding the Impacts of Katrina and Rita on Energy Industry Infrastructure." (2008). American Chemical Society National Meetings, New Orleans, Louisiana. April 7, 2008.

6. "Determining the Economic Value of Coastal Preservation and Restoration on Critical Energy Infrastructure." (2007). With Kristi A. R. Darby and Michelle Barnett. International Association for Energy Economics, Wellington, New Zealand, February 19, 2007.

7. "Regulatory Issues in Rate Design, Incentives, and Energy Efficiency." (2007). 34th Annual Public Utilities Research Center Conference, University of Florida. Gainesville, FL. February 16, 2007.

8. "An Examination of LNG Development on the Gulf of Mexico." (2007). With Kristi A.R. Darby. US Department of the Interior, Minerals Management Service. 24th Annual Information Technology Meeting. New Orleans, LA. January 9.

9. "OCS-Related Infrastructure on the GOM: Update and Summary of Impacts." (2007). US Department of the Interior, Minerals Management Service. 24th Annual Information Technology Meeting. New Orleans, LA. January 10.

10. "The Economic Value of Coastal Preservation and Restoration on Critical Energy Infrastructure." (2006). With Michelle Barnett. Third National Conference on Coastal and Estuarine Habitat Restoration. Restore America's Estuaries. New Orleans, Louisiana, December 11.

11. "The Impact of Implementing a 20 Percent Renewable Portfolio Standard in New Jersey." (2006). With Seth E. Cureington. Mid-Continent Regional Science Association 37th Annual Conference, Purdue University, Lafayette, Indiana, June 9.

12. "The Impacts of Hurricane Katrina and Rita on Energy infrastructure Along the Gulf Coast." (2006). Environment Canada: 2006 Artic and Marine Oilspill Program. Vancouver, British Columbia, Canada.

13. "Hurricanes, Energy Markets, and Energy Infrastructure in the Gulf of Mexico: Experiences and Lessons Learned." (2006). With Kristi A.R. Darby and Seth E. Cureington. 29th Annual IAEE International Conference, Potsdam, Germany, June 9.

14. "An Examination of the Opportunities for Drilling Incentives on State Leases in Louisiana." (2005). With Kristi A.R. Darby. 28th Annual IAEE International Conference, Taipei, Taiwan (June).

15. "Fiscal Mechanisms for Stimulating Oil and Gas Production on Marginal Leases." (2004). With Jeffrey M. Burke. International Association of Energy Economics Annual Conference, Washington, D.C. (July).

16. "GIS and Applied Economic Analysis: The Case of Alaska Residential Natural Gas Demand." (2003). With Dmitry V. Mesyanzhinov. Presented at the Joint Meeting of the East Lakes and West Lakes Divisions of the Association of American Geographers in Kalamazoo, MI, October 16-18.

17. "Are There Any In-State Uses for Alaska Natural Gas?" (2002). With Dmitry V. Mesyanzhinov and William E. Nebesky. IAEE/USAEE 22nd Annual North American Conference: "Energy Markets in Turmoil: Making Sense of It All." Vancouver, British Columbia, Canada. October 7.

18. "The Economic Impact of State Oil and Gas Leases on Louisiana." (2002). With Dmitry V. Mesyanzhinov. 2002 National IMPLAN Users' Conference. New Orleans, Louisiana, September 4-6.

19. "Moving to the Front of the Lines: The Economic Impact of Independent Power Plant Development in Louisiana." (2002). With Dmitry V. Mesyanzhinov and Williams O. Olatubi. 2002 National IMPLAN Users' Conference. New Orleans, Louisiana, September 4-6.

20. "New Consistent Approach to Modeling Regional Economic Impacts of Offshore Oil and Gas Activities in the Gulf of Mexico." (2002). With Vicki Zatarain. 2002 National IMPLAN Users' Conference. New Orleans, Louisiana, September 4-6.

21. "Distributed Energy Resources, Energy Efficiency, and Electric Power Industry Restructuring." (1999). American Society of Environmental Science Fourth Annual Conference. Baton Rouge, Louisiana. December.

22. "Estimating Efficiency Opportunities for Coal Fired Electric Power Generation: A DEA Approach." (1999). With Williams O. Olatubi. Southern Economic Association Sixty-ninth Annual Conference. New Orleans, November.

23. "Applied Approaches to Modeling Regional Power Markets." (1999.) With Robert F. Cope. Southern Economic Association Sixty-ninth Annual Conference. New Orleans, November 1999.

24. "Parametric and Non-Parametric Approaches to Measuring Efficiency Potentials in Electric Power Generation." (1999). With Williams O. Olatubi. International Atlantic Economic Society Annual Conference, Montreal, October.

25. "Asymmetric Choice and Customer Benefits: Lessons from the Natural Gas Industry." (1999). With Rachelle F. Cope and Dmitry Mesyanzhinov. International Association of Energy Economics Annual Conference. Orlando, Florida. August.

26. "Modeling Regional Power Markets and Market Power." (1999). With Robert F. Cope. Western Economic Association Annual Conference. San Diego, California. July.

27. "Economic Impact of Offshore Oil and Gas Activities on Coastal Louisiana" (1999). With Dmitry Mesyanzhinov. Annual Meeting of the Association of American Geographers. Honolulu, Hawaii. March.

28. "Empirical Issues in Electric Power Transmission and Distribution Cost Modeling." (1998). With Robert F. Cope and Dmitry Mesyanzhinov. Southern Economic Association. Sixty-Eighth Annual Conference. Baltimore, Maryland. November.

29. "Modeling Electric Power Markets in a Restructured Environment." (1998). With Robert F. Cope and Dan Rinks. International Association for Energy Economics Annual Conference. Albuquerque, New Mexico. October.

30. "Benchmarking Electric Utility Distribution Performance." (1998) With Robert F. Cope and Dmitry Mesyanzhinov. Western Economic Association, Seventy-sixth Annual Conference. Lake Tahoe, Nevada. June.

31. "Power System Operations, Control, and Environmental Protection in a Restructured Electric Power Industry." (1998). With Fred I. Denny. IEEE Large Engineering Systems Conference on Power Engineering. Nova Scotia, Canada. June.

32. "Benchmarking Electric Utility Transmission Performance." (1997). With Robert F. Cope and Dmitry Mesyanzhinov. Southern Economic Association, Sixty-seventh Annual Conference. Atlanta, Georgia. November 21-24.

33. "A Non-Linear Programming Model to Estimate Stranded Generation Investments in a Deregulated Electric Utility Industry." (1997). With Robert F. Cope and Dan Rinks. Institute for Operations Research and Management Science Annual Conference. Dallas Texas. October 26-29.

34. "New Paradigms for Power Engineering Education." (1997). With Fred I. Denny. International Association of Science and Technology for Development, High Technology in the Power Industry Conference. Orlando, Florida. October 27-30

35. "Cogeneration and Electric Power Industry Restructuring." (1997). With Andrew N. Kleit. Western Economic Association, Seventy-fifth Annual Conference. Seattle, Washington. July 9-13.

36. "The Unintended Consequences of the Public Utilities Regulatory Policies Act of 1978." (1997). National Policy History Conference on the Unintended Consequences of Policy Decisions. Bowling Green State University. Bowling Green, Ohio. June 5-7.

37. "Assessing Environmental and Safety Risks of the Expanding Role of Independents in E&P Operations on the Gulf of Mexico OCS." (1996). With Allan Pulsipher, Omowumi Iledare, Dmitry Mesyanzhinov, and Bob Baumann. U.S. Department of Interior, Minerals Management Service, 16th Annual Information Transfer Meeting. New Orleans, Louisiana.

38. "Empirical Modeling of the Risk of a Petroleum Spill During E&P Operations: A Case Study of the Gulf of Mexico OCS." (1996). With Omowumi Iledare, Allan Pulsipher, and Dmitry Mesyanzhinov. Southern Economic Association, Sixty-Sixth Annual Conference. Washington, D.C.

39. "Input Price Fluctuations, Total Factor Productivity, and Price Cap Regulation in the Telecommunications Industry" (1996). With Farhad Niami. Southern Economic Association, Sixty-Sixth Annual Conference. Washington, D.C.

40. "Recovery of Stranded Investments: Comparing the Electric Utility Industry to Other Recently Deregulated Industries" (1996). With Farhad Niami and Dmitry Mesyanzhinov. Southern Economic Association, Sixty-Sixth Annual Conference. Washington, D.C.

41. "Spatial Perspectives on the Forthcoming Deregulation of the U.S. Electric Utility Industry." (1996) With Dmitry Mesyanzhinov. Southwest Association of American Geographers Annual Meeting. Norman, Oklahoma.

42. "Comparing the Safety and Environmental Performance of Offshore Oil and Gas Operators." (1995). With Allan Pulsipher, Omowumi Iledare, Dmitry Mesyanzhinov, William Daniel, and Bob Baumann. U.S. Department of Interior, Minerals Management Service, 15th Annual Information Transfer Meeting. New Orleans, Louisiana.

43. "Empirical Determinants of Nuclear Power Plant Disallowances." (1995). Southern Economic Association, Sixty-Fifth Annual Conference. New Orleans, Louisiana.

44. "A Cross-Sectional Model of IntraLATA MTS Demand." (1995). Southern Economic Association, Sixty-Fifth Annual Conference. New Orleans, Louisiana.

ACADEMIC SEMINARS AND PRESENTATIONS

1. "Air Emissions Regulation and Policy: The Recently Proposed Cross State Air Pollution Rule and the Implications for Louisiana Power Generation." Lecture before School of the Coast & Environment. November 5, 2011.

2. "Energy Regulation: Overview of Power and Gas Regulation." Lecture before School of the Coast & Environment, Course in Energy Policy and Law. October 5, 2009.

3. "Trends and Issues in Renewable Energy." Presentation before the School of the Coast & Environment, Louisiana State University. Spring Guest Lecture Series. May 4, 2007.

4. "CES Research Projects and Status." Presentation before the U.S. Department of the Interior, Minerals Management Service, Outer Continental Shelf Scientific Committee Meeting, New Orleans, LA May 22, 2007.

5. "Hurricane Impacts on Energy Production and Infrastructure." Presentation Before the 53rd Mineral Law Institute, Louisiana State University. April 7, 2006.

6. "Trends and Issues in the Natural Gas Industry and the Development of LNG: Implications for Louisiana. (2004) 51st Mineral Law Institute, Louisiana State University, Baton Rouge, LA. April 2, 2004.

7. "Electric Restructuring and Conservation." (2001). Presentation before the Department of Electrical Engineering, McNesse State University. Lake Charles, Louisiana. May 2, 2001.

8. "Electric Restructuring and the Environment." (1998). Environment 98: Science, Law, and Public Policy. Tulane University. Tulane Environmental Law Clinic. March 7, New Orleans, Louisiana.

9. "Electric Restructuring and Nuclear Power." (1997). Louisiana State University. Department of Nuclear Science. November 7, Baton Rouge, Louisiana.

10. "The Empirical Determinants of Co-generated Electricity: Implications for Electric Power Industry Restructuring." (1997). With Andrew N. Kleit. Florida State University. Department of Economics: Applied Microeconomics Workshop Series. October 17, Tallahassee, Florida.

PROFESSIONAL AND CIVIC PRESENTATIONS

1. "Natural Gas & Electric Power Coordination Issues and Challenges." (2013). Utilities State Government Organization Conference, Pointe Clear, Alabama. July 9.

2. "Louisiana Unconventional Natural Gas and Industrial Redevelopment." (2013). Risk Management Association Luncheon, March 21.

3. "Unconventional Resources and Louisiana's Manufacturing Development Renaissance." (2013). Baton Rouge Press Club, De La Ronde Hall, Baton Rouge, LA, January 28.

4. "New Industrial Operations Leveraged by Unconventional Natural Gas." (2013) American Petroleum Institute-Louisiana Chapter. Lafayette, LA, Petroleum Club, January 14.

5. "What's Going on with Energy? How Unconventional Oil and Gas Development is Impacting Renewables, Efficiency, Power Markets, and All that Other Stuff." (2012). Atlanta Economics Club Monthly Meeting. Atlanta, GA. December 11.

6. "Trends, Issues, and Market Changes for Crude Oil and Natural Gas." (2012). East Iberville Community Advisory Panel Meeting. St. Gabriel, LA. September 26.

7. "Game Changers in Crude and Natural Gas Markets." (2012). Chevron Community Advisory Panel Meeting. Belle Chase, LA, September 17.

8. "The Outlook for Renewables in a Changing Power and Natural Gas Market." (2012). Louisiana Biofuels and Bioprocessing Summit. Baton Rouge, LA. September 11.

9. "The Changing Dynamics of Crude and Natural Gas Markets." (2012). Chalmette Refining Community Advisory Panel Meeting. Chalmette, LA, September 11.

10. "The Really Big Game Changer: Crude Oil Production from Shale Resources and the Tuscaloosa Marine Shale." (2012). Baton Rouge Chamber of Commerce Board Meeting. Baton Rouge, LA, June 27.

11. "The Impact of Changing Natural Gas Prices on Renewables and Energy Efficiency." (2012). NASUCA Gas Committee Conference Call/Webinar. 12 June 2012.

12. "Issues in Gas-Renewables Coordination: How Changes in Natural Gas Markets Potentially Impact Renewable Development" (2012). Energy Bar Association, Louisiana Chapter, Annual Meeting, New Orleans, LA. April 12, 2012.

13. "Issues in Natural Gas End-Uses: Are We Really Focusing on the Real Opportunities?" (2012). Energy Bar Association, Louisiana Chapter, Annual Meeting, New Orleans, LA. April 12, 2012.

14. "The Impact of Legacy Lawsuits on Conventional Oil and Gas Drilling in Louisiana." (2012). Louisiana Oil and Gas Association Annual Meeting, Lake Charles, LA. February 27, 2012.

15. "The Impact of Legacy Lawsuits on Conventional Oil and Gas Drilling in Louisiana." (2012) Louisiana Oil and Gas Association Annual Meeting. Lake Charles, Louisiana. February 27, 2012.

16. "Louisiana's Unconventional Plays: Economic Opportunities, Policy Challenges. Louisiana Mid-Continent Oil and Gas Association 2012 Annual Meeting. (2012) New Orleans, Louisiana. January 26, 2012.

17. "EPA's Recently Proposed Cross State Air Pollution Rule ("CSAPR") and Its Impacts on Louisiana." (2011). Bossier Chamber of Commerce. November 18, 2011.

18. "Facilitating the Growth of America's Natural Gas Advantage." (2011). BASF U.S. Shale Gas Workshop Management Meeting. Florham Park, New Jersey. November 1, 2011.

19. "CSAPR and EPA Regulations Impacting Louisiana Power Generation." (2011). Air and Waste Management Association (Louisiana Section) Fall Conference. Environmental Focus 2011: a Multi-Media Forum. Baton Rouge, LA. October 25, 2011.

20. "Natural Gas Trends and Impact on Industrial Development." (2011). Central Gulf Coast Industrial Alliance Conference. Arthur R. Outlaw Convention Center. Mobile, AL. September 22, 2011.

21. "Energy Market Changes and Policy Challenges." (2011). Southeast Manpower Tripartite Alliance ("SEMTA") Summer Conference. Nashville, TN September 2, 2011.

22. "EPA Regulations, Rates & Costs: Implications for U.S. Ratepayers." (2011). Workshop: "A Smarter Approach to Improving Our Environment." 38th Annual American Legislative Exchange Council ("ALEC") Meetings. New Orleans, LA. August 5, 2011.

23. Panelist/Moderator. Workshop: "Why Wait? Start Energy Independence Today." 38th Annual American Legislative Exchange Council ("ALEC") Meetings. New Orleans, LA. August 4, 2011.

24. "Facilitating the Growth of America's Natural Gas Advantage." Texas Chemical Council, Board of Directors Summer Meeting. San Antonio, TX. July 28, 2011.

25. "Creating Ratepayer Benefits by Reconciling Recent Gas Supply Opportunities with Past Policy Initiatives." National Association of State Utility Consumer Advocates ("NASUCA"), Monthly Gas Committee Meeting. July 12, 2011.

26. "Energy Market Trends and Policies: Implications for Louisiana." (2011). Lakeshore Lion's Club Monthly Meeting. Baton Rouge, Louisiana. June 20, 2011.

27. "America's Natural Gas Advantage: Securing Benefits for Ratepayers Through Paradigm Shifts in Policy." Southeastern Association of Regulatory Commissioners ("SEARUC") Annual Meeting. Nashville, Tennessee. June 14, 2011.

28. "Learning Together: Building Utility and Clean Energy Industry Partnerships in the Southeast." (2011). American Solar Energy Society National Solar Conference. Raleigh Convention Center, Raleigh, North Carolina. May 20, 2011.

29. "Louisiana Energy Outlook and Trends." (2011). Executive Briefing. Counsul General of Canada. LSU Center for Energy Studies, Baton Rouge, Louisiana. May 24, 2011.

30. "Louisiana's Natural Gas Advantage: Can We Hold It? Grow It? Or Do We Need to be Worrying About Other Problems?" (2011). Louisiana Chemical Association Annual Legislative Conference, Baton Rouge, Louisiana, May 5, 2011.

31. "Energy Outlook and Trends: Implications for Louisiana. (2011). Executive Briefing, Legislative Staff, Congressman William Cassidy. LSU Center for Energy Studies, Baton Rouge, Louisiana. March 25, 2011.

32. "Regulatory Issues in Inflation Adjustment Mechanisms and Allowances." (2011). Gas Committee, National Association of State Utility Consumer Advocates ("NASUCA"). February 15, 2011.

33. "Regulatory Issues in Inflation Adjustment Mechanisms and Allowances." (2010). 2010 Annual Meeting, National Association of State Utility Consumer Advocates ("NASUCA"), Omni at CNN Center, Atlanta, Georgia, November 16, 2010.

34. "How Current and Proposed Energy Policy Impacts Consumers and Ratepayers." (2010). 122nd Annual Meeting, National Association of Regulatory Utility Commissioners

("NARUC"), Omni at CNN Center, Atlanta, Georgia, November 15, 2010.

35. "Energy Outlook: Trends and Policies." (2010). 2010 Tri-State Member Service Conference; Arkansas, Louisiana, and Mississippi Electric Cooperatives. L'Auberge du Lac Casino Resort, Lake Charles, Louisiana, October 14, 2010.

36. "Deepwater Moratorium and Louisiana Impacts." (2010). The Energy Council Annual Meeting. Gulf of Mexico Deepwater Horizon Accident, Response, and Policy. Beau Rivage Conference Center. Biloxi, Mississippi. September 25, 2010.

37. "Overview on Offshore Drilling and Production Activities in the Aftermath of Deepwater Horizon." (2010) Jones Walker Banking Symposium. The Oil Spill: What Will it Mean for Banks in the Region? New Orleans, Louisiana. August 31, 2010.

38. "Long-Term Energy Sector Impacts from the Oil Spill." (2010). Second Annual Louisiana Oil & Gas Symposium. The BP Gulf Oil Spill: Long-Term Impacts and Strategies. Baton Rouge Geological Society. August 16, 2010.

39. "Overview and Issues Associated with the Deepwater Horizon Accident." (2010). Global Interdependence Meeting on Energy Issues. Baton Rouge, LA. August 12, 2010.

40. "Overview and Issues Associated with the Deepwater Horizon Accident." (2010). Regional Roundtable Webinar. National Association for Business Economics. August 10, 2010.

41. "Deepwater Moratorium: Overview of Impacts for Louisiana." Louisiana Association of Business and Industry Meeting. Baton Rouge, LA. June 25, 2010.

42. Moderator. Senior Executive Roundtable on Industrial Energy Efficiency. U.S. Department of Energy Conference on Industrial Efficiency. Office of Renewable Energy and Energy Efficiency. Royal Sonesta Hotel, New Orleans, LA. May 21, 2010.

43. "The Energy Outlook: Trends and Policies Impacting Southeastern Natural Gas Supply and Demand Growth." Second Annual Local Economic Analysis and Research Network ("LEARN") Conference. Federal Reserve Bank of Atlanta. March 29, 2010.

44. "Natural Gas Supply Issues: Gulf Coast Supply Trends and Implications for Louisiana." Energy Bar Association, New Orleans Chapter Meeting. Jones Walker Law Firm. January 28, 2010, New Orleans, LA.

45. "Potential Impacts of Federal Greenhouse Gas Legislation on Louisiana Industry." LCA Government Affairs Committee Meeting. November 10, 2009. Baton Rouge, LA

46. "Regulatory and Ratemaking Issues Associated with Cost and Revenue Tracker Mechanisms." National Association of State Utility Consumer Advocates ("NASUCA") Annual Meeting. November 10, 2009.

47. "Louisiana's Stakes in the Greenhouse Gas Debate." Louisiana Chemical Association

and Louisiana Chemical Industry Alliance Annual Meeting: The Billing Dollar Budget Crisis: Catastrophe or Change? New Orleans, LA.

48. "Gulf Coast Energy Outlook: Issues and Trends." Women's Energy Network, Louisiana Chapter. September 17, 2009. Baton Rouge, LA.

49. "Gulf Coast Energy Outlook: Issues and Trends." Natchez Area Association of Energy Service Companies. September 15, 2009, Natchez, MS.

50. "The Small Picture: The Cost of Climate Change to Louisiana." Louisiana Association of Business and Industry, U.S. Chamber of Commerce, Louisiana Oil and Gas Association, and LSU Center for Energy Studies Conference: Can Louisiana Make a Buck After Climate Change Legislation? August 21, 2009. Baton Rouge, LA.

51. "Carbon Legislation and Clean Energy Markets: Policy and Impacts." National Association of Conservation Districts, South Central Region Meeting. August 14, 2009. Baton Rouge, LA.

52. "Evolving Carbon and Clean Energy Markets." The Carbon Emissions Continuum: From Production to Consumption." Jones Walker Law Firm and LSU Center for Energy Studies Workshop. June 23, 2009. Baton Rouge, LA

53. "Potential Impacts of Cap and Trade on Louisiana Ratepayers: Preliminary Results." (2009). Briefing before the Louisiana Public Service Commission. Business and Executive Meeting, May 12, 2009. Baton Rouge, LA.

54. "Natural Gas Outlook." (2009). Briefing before the Louisiana Public Service Commission. Business and Executive Meeting, May 12, 2009. Baton Rouge, LA.

55. "Gulf Coast Energy Outlook: Issues and Trends." (2009). ISA-Lafayette Technical Conference & Expo. Cajundome Conference Center. Lafayette, Louisiana. March 12, 2009.

56. "The Cost of Energy Independence, Climate Change, and Clean Energy Initiatives on Utility Ratepayers." (2009). National Association of Business Economists (NABE). 25th Annual Washington Economic Policy Conference: Restoring Financial and Economic Stability. Arlington, VA March 2, 2009.

57. Panelist, "Expanding Exploration of the U.S. OCS" (2009). Deep Offshore Technology International Conference and Exhibition. PennWell. New Orleans, Louisiana. February 4, 2009.

58. "Gulf Coast Energy Outlook." (2008.) Atmos Energy Regional Management Meeting. Louisiana and Mississippi Division. New Orleans, Louisiana. October 8, 2008.

59. "Background, Issues, and Trends in Underground Hydrocarbon Storage." (2008). Presentation before the LSU Center for Energy Studies Industry Advisory Board Meeting. Baton Rouge, Louisiana. August 27, 2008.

60. "Greenhouse Gas Regulations and Policy: Implications for Louisiana." (2008). Presentation before the Praxair Customer Seminar. Houston, Texas, August 14, 2008.

61. "Market and Regulatory Issues in Alternative Energy and Louisiana Initiatives." (2008). Presentation before the 2008 Statewide Clean Cities Coalition Conference: Making Sense of Alternative Fuels and Advanced Technologies. New Orleans, Louisiana, March 27, 2008.

62. "Regulatory Issues in Rate Design, Incentives, and Energy Efficiency." (2007) Presentation before the New Hampshire Public Utilities Commission. Workshop on Energy Efficiency and Revenue Decoupling. November 7, 2007.

63. "Regulatory Issues for Consumer Advocates in Rate Design, Incentives, and Energy Efficiency." (2007). National Association of State Utility Consumer Advocates, Mid-Year Meeting. June 12, 2007.

64. "Regulatory and Policy Issues in Nuclear Power Plant Development." (2007). LSU Center for Energy Studies Industry Advisory Council Meeting. Baton Rouge, LA. March 23, 2007.

65. "Oil and Gas in the Gulf of Mexico: A North American Perspective." (2007). Canadian Consulate, Heads of Mission EnerNet Workshop, Houston, Texas. March 20, 2007.

66. "Regulatory Issues for Consumer Advocates in Rate Design, Incentives & Energy Efficiency. (2007). National Association of State Utility Consumer Advocates ("NASUCA") Gas Committee Monthly Meeting. February 13, 2006.

67. "Recent Trends in Natural Gas Markets." (2006). National Association of Regulatory Utility Commissioners, 118th Annual Convention. Miami, FL November 14, 2006.

68. "Energy Markets: Recent Trends, Issues & Outlook." (2006). Association of Energy Service Companies (AESC) Meeting. Petroleum Club, Lafayette, LA, November 8, 2006.

69. "Energy Outlook" (2006). National Business Economics Issues Council. Quarterly Meeting, Nashville, TN, November 1-2, 2006.

70. "Global and U.S. Energy Outlook." (2006). Energy Virginia Conference. Virginia Military Institute, Lexington, VA October 17, 2006.

71. "Interdependence of Critical Energy Infrastructure Systems." (2006). Cross Border Forum on Energy Issues: Security and Assurance of North American Energy Systems. Woodrow Wilson Center for International Scholars. Washington, DC, October 13, 2006.

72. "Determining the Economic Value of Coastal Preservation and Restoration on Critical Energy Infrastructure." (2006) The Economic and Market Impacts of Coastal Restoration: America's Wetland Economic Forum II. Washington, DC September 28, 2006.

73. "Relationships between Power and Other Critical Energy Infrastructure." (2006). Rebuilding the New Orleans Region: Infrastructure Systems and Technology Innovation Forum. United Engineering Foundation. New Orleans, LA, September 24-25, 2006.

74. "Outlook, Issues, and Trends in Energy Supplies and Prices." (2006.) Presentation to the Southern States Energy Board, Associate Members Meeting. New Orleans, Louisiana. July 14, 2006.

75. "Energy Sector Outlook." (2006). Baton Rouge Country Club Meeting. Baton Rouge, Louisiana. July 11, 2006.

76. "Oil and Gas Industry Post 2005 Storm Events." (2006). American Petroleum Institute, Teche Chapter. Production, Operations, and Regulations Annual Meeting. Lafayette, Louisiana. June 29, 2006.

77. "Concentration of Energy Infrastructure in Hurricane Regions." (2006). Presentation before the National Commission on Energy Policy Forum: Ending the Stalemate on LNG Facility Siting. Washington, DC. June 21, 2006.

78. "LNG—A Premier." (2006). Presentation Given to the U.S. Department of Energy's "LNG Forums." Los Angeles, California. June 1, 2006.

79. "Regional Energy Infrastructure, Production and Outlook." (2006). Executive Briefing for Board of Directors, Louisiana Oil and Gas Plc., Enhanced Exploration, Inc. and Energy Self-Service, Inc. Covington, Louisiana, May 12, 2006.

80. "The Impacts of the Recent Hurricane Season on Energy Production and Infrastructure and Future Outlook." Presentation before the Industrial Energy Technology Conference 2006. New Orleans, Louisiana, May 9, 2006.

81. "Update on Regional Energy Infrastructure and Production." (2006). Executive Briefing for Delegation Participating in U.S. Department of Commerce Gulf Coast Business Investment Mission. Baton Rouge, Louisiana May 5, 2006.

82. "Hurricane Impacts on Energy Production and Infrastructure." (2006). Presentation before the Interstate Natural Gas Association of America Mid-Year Meeting. Hyatt Regency Hill Country. April 21, 2006.

83. "LNG—A Premier." Presentation Given to the U.S. Department of Energy's "LNG Forums." Astoria, Washington. April 28, 2006.

84. Natural Gas Market Outlook. Invited Presentation Given to the Georgia Public Service Commission and Staff. Georgia Institute of Technology, Atlanta, Georgia. March 10, 2006.

85. The Impacts of Hurricanes Katrina and Rita on Louisiana's Energy Industry. Presentation to the Louisiana Economic Development Council. Baton Rouge, Louisiana. March 8, 2006.

86. Energy Markets: Hurricane Impacts and Outlook. Presentation to the 2006 Louisiana Independent Oil and Gas Association Annual Conference. L'Auberge du Lac Resort and Casino. Lake Charles, Louisiana. March 6, 2006

87. Energy Market Outlook and Update on Hurricane Damage to Energy Infrastructure. Presentation to the Energy Council 2005 Global Energy and Environmental Issues Conference. Santa Fe, New Mexico, December 10, 2005.

88. "Putting Our Energy Infrastructure Back Together Again." Presentation Before the 117th Annual Convention of the National Association of Regulatory Utility Commissioners (NARUC). November 15, 2005. Palm Springs, CA

89. "Hurricanes and the Outlook for Energy Markets." Presentation before the Baton Rouge Rotary Club. November 9, 2005, Baton Rouge, LA.

90. "Hurricanes, Energy Supplies and Prices." Presentation before the Louisiana Department of Natural Resources and Atchafalaya Basin Committee Meeting. November 8, 2005. Baton Rouge, LA.

91. "The Impact of the Recent Hurricane's on Louisiana's Energy Industry." Presentation before the Louisiana Independent Oil and Gas Association Board of Directors Meeting. November 8, 2005. Baton Rouge, LA.

92. "The Impact of the Recent Hurricanes on Louisiana's Infrastructure and National Energy Markets." Presentation before the Baton Rouge City Club Distinguished Speaker Series. October 13, 2005. Baton Rouge, LA.

93. "The Impact of the Recent Hurricanes on Louisiana's Infrastructure and National Energy Markets." Presentation before Powering Up: A Discussion About the Future of Louisiana's Energy Industry. Special Lecture Series Sponsored by the Kean Miller Law Firm. October 13, 2005. Baton Rouge, LA.

94. "The Impact of Hurricane Katrina on Louisiana's Energy Infrastructure and National Energy Markets." Special Lecture on Hurricane Impacts, LSU Center for Energy Studies, September 29, 2005.

95. "Louisiana Power Industry Overview." Presentation before the Clean Air Interstate Rule Implementation Stakeholders Meeting. August 11, 2005. Louisiana Department of Environmental Quality.

96. "CES 2005 Legislative Support and Outlook for Energy Markets and Policy." Presentation before the LMOGA/LCA Annual Post-Session Legislative Committee Meeting. August 10-13, 2005. Perdido Key, Florida.

97. "Electric Restructuring: Past, Present, and Future." Presentation to the Southeastern Association of Tax Administrators Annual Conference. Sheraton Hotel and Conference Facility. New Orleans, LA July 12, 2005.

98. "The Outlook for Energy." Lagniappe Studies Continuing Education Course. Baton Rouge, LA. July 11, 2005.

99. "The Outlook for Energy." Sunshine Rotary Club. Baton Rouge, LA. April 27, 2005.

100. "Background and Overview of LNG Development." Energy Council Workshop on LNG/CNG. Biloxi, Ms: Beau Rivage Resort and Hotel, April 9, 2005.

101. "Natural Gas Supply, Prices, and LNG: Implications for Louisiana Industry." Cytec Corporation Community Advisory Panel. Fortier, LA January 14, 2005.

102. "The Economic Opportunities for a Limited Industrial Retail Choice Plan." Louisiana Department of Economic Development. Baton Rouge, Louisiana. November 19, 2004.

103. "Energy Issues for Industrial Customers of Gas and Power." Louisiana Association of Business and Industry, Energy Council Meeting. Baton Rouge, Louisiana. October 11, 2004.

104. "Energy Issues for Industrial Customers of Gas and Power." Annual Meeting of the Louisiana Chemical Association and the Louisiana Chemical Industry Alliance. Point Clear, Alabama. October 8, 2004.

105. "Energy Issues for Industrial Customers of Gas and Power." American Institute of Chemical Engineers – New Orleans Section. New Orleans, LA. September 22, 2004.

106. "Natural Gas Supply, Prices and LNG: Implications for Louisiana Industry." Dow Chemical Company Community Advisory Panel Meeting. Plaquemine, LA. August 9, 2004.

107. "Energy Issues for Industrial Customers of Gas and Power." Louisiana Chemical Association Post-Legislative Meeting. Springfield, LA. August 9, 2004.

108. "LNG In Louisiana." Joint Meeting of the Louisiana Economic Development Council and the Governors Cabinet Advisory Council. Baton Rouge, LA. August 5, 2004.

109. "Louisiana Energy Issues." Louisiana Mid-Continent Oil and Gas Association Post Legislative Meetings. Sandestin, Florida. July 28, 2004.

110. "The Gulf South: Economic Opportunities Related to LNG." Presentation before the Energy Council's 2004 State and Provincial Energy and Environmental Trends Conference. Point Clear, AL, June 26, 2004.

111. "Natural Gas and LNG Issues for Louisiana." Presentation before the Rhodia Community Advisory Panel. May 20, 2004, Baton Rouge, LA.

112. "The Economic Opportunities for LNG Development in Louisiana." Presentation before the Louisiana Chemical Association Plant Managers Meeting. May 27, 2004. Baton Rouge, LA.

113. "The Economic Opportunities for LNG Development in Louisiana." Presentation before the Louisiana Chemical Association/Louisiana Chemical Industry Alliance Legislative Conference. May 26, 2004. Baton Rouge, LA.

114. "The Economic Opportunities for LNG Development in Louisiana." Presentation before the Petrochemical Industry Cluster, Greater New Orleans, Inc. May 19, 2004, Destrehan, LA.

115. "Industry Development Issues for Louisiana: LNG, Retail Choice, and Energy." Presentation before the LSU Center for Energy Studies Industry Associates. May 14, 2004, Baton Rouge, LA.

116. "The Economic Opportunities for LNG Development in Louisiana." Presentation before the Board of Directors, Greater New Orleans, Inc. May 13, 2004, New Orleans, LA.

117. "Natural Gas Outlook: Trends and Issues for Louisiana." Presentation before the Louisiana Joint Agricultural Association Meetings. January 14, 2004, Hotel Acadiana, Lafayette, Louisiana.

118. "Natural Gas Outlook" Presentation before the St. James Parish Community Advisory Panel Meeting. January 7, 2004, IMC Production Facility, Convent, Louisiana.

119. "Competitive Bidding in the Electric Power Industry." Presentation before the Association of Energy Engineers. Business Energy Solutions Expo. December 11-12, 2003, New Orleans, Louisiana.

120. "Regional Transmission Organization in the South: The Demise of SeTrans" Presentation before the LSU Center for Energy Studies Industry Associates Advisory Council Meeting. December 9, 2003. Baton Rouge, Louisiana.

121. "Affordable Energy: The Key Component to a Strong Economy." Presentation before the National Association of Regulatory Utility Commissioners ("NARUC"), November 18, 2003, Atlanta, Georgia.

122. "Natural Gas Outlook." Presentation before the Louisiana Chemical Association, October 17, 2003, Pointe Clear, Alabama.

123. "Issues and Opportunities with Distributed Energy Resources." Presentation before the Louisiana Biomass Council. April 17, 2003, Baton Rouge, Louisiana.

124. "What's Happened to the Merchant Energy Industry? Issues, Challenges, and Outlook" Presentation before the LSU Center for Energy Studies Industry Associates Advisory Council Meeting. November 12, 2002. Baton Rouge, Louisiana.

125. "An Introduction to Distributed Energy Resources." Presentation before the U.S. Department of Energy, Office of Renewable Energy and Energy Efficiency, State Energy Program/Rebuild America Conference, August 1, 2002, New Orleans, Louisiana.

126. "Merchant Energy Development Issues in Louisiana." Presentation before the Program Committee of the Center for Legislative, Energy, and Environmental Research (CLEER), Energy Council. April 19, 2002.

127. "Power Plant Siting Issues in Louisiana." Presentation before 24th Annual Conference on Waste and the Environment. Sponsored by the Louisiana Department of Environmental Quality. Lafayette, Louisiana, Cajundome. March 12, 2002.

128. "Merchant Power and Deregulation: Issues and Impacts." Presentation before the Air and Waste Management Association Annual Meeting. Baton Rouge, LA, November 15, 2001.

129. "Moving to the Front of the Lines: The Economic Impact of Independent Power Production in Louisiana." Presentation before the LSU Center for Energy Studies Merchant Power Generation and Transmission Conference, Baton Rouge, LA. October 11, 2001.

130. "Economic Impacts of Merchant Power Plant Development in Mississippi." Presentation before the U.S. Oil and Gas Association Annual Oil and Gas Forum. Jackson, Mississippi. October 10, 2001.

131. "Economic Opportunities for Merchant Power Development in the South." Presentation before the Southern Governor's Association/Southern State Energy Board Meetings. Lexington, KY. September 9, 2001.

132. "The Changing Nature of the Electric Power Business in Louisiana." Presentation before the Louisiana Department of Environmental Quality. Baton Rouge, LA, August 27, 2001.

133. "Power Business in Louisiana: Background and Issues." Presentation before the Louisiana Interagency Group on Merchant Power Development . Baton Rouge, LA, July 16, 2001.

134. "The Changing Nature of the Electric Power Business in Louisiana: Background and Issues." Presentation before the Louisiana Office of the Governor. Baton Rouge, LA, July 16, 2001.

135. "The Changing Nature of the Electric Power Business in Louisiana: Background and Issues." Presentation before the Louisiana Department of Economic Development. Baton Rouge, LA, July 3, 2001.

136. "The Economic Impacts of Merchant Power Plant Development In Mississippi." Presentation before the Mississippi Public Service Commission. Jackson, Mississippi, March 20, 2001.

137. "Energy Conservation and Electric Restructuring." With Ritchie D. Priddy. Presentation before the Louisiana Department of Natural Resources. Baton Rouge, Louisiana, October 23, 2000.

138. "Pricing and Regulatory Issues Associated with Distributed Energy." Joint Conference by Econ One Research, Inc., the Louisiana State University Distributed Energy Resources Initiative, and the University of Houston Energy Institute: "Is the Window Closing for Distributed Energy?" Houston, Texas, October 13, 2000.

139. "Electric Reliability and Merchant Power Development Issues." Technical Meetings of the Louisiana Public Service Commission. Baton Rouge, LA. August 29, 2000.

140. "A Introduction to Distributed Energy Resources." Summer Meetings, Southeastern Association of Regulatory Utility Commissioners (SEARUC). New Orleans, LA. June 27, 2000.

141. Roundtable Moderator/Discussant. Mid-South Electric Reliability Summit. U.S. Department of Energy. New Orleans, Louisiana. April 24, 2000.

142. "Electricity 101: Definitions, Precedents, and Issues." Energy Council's 2000 Federal Energy and Environmental Matters Conference. Loews L'Enfant Plaza Hotel, Washington, D.C. March 11-13, 2000.

143. "LSU/CES Distributed Energy Resources Initiatives." Los Alamos National Laboratories. Office of Energy and Sustainable Systems. Los Alamos, New Mexico. February 16, 2000.

144. "Distributed Energy Resources Initiatives." Louisiana State University, Center for Energy Studies Industry Associates Meeting. Baton Rouge, Louisiana. December 15, 1999.

145. "Merchant Power Opportunities in Louisiana." Louisiana Mid-Continent Oil and Gas Association (LMOGA) Power Generation Committee Meetings. Baton Rouge, Louisiana. November 10, 1999.

146. Roundtable Discussant. "Environmental Regulation in a Restructured Market" The Big E: How to Successfully Manage the Environment in the Era of Competitive Energy. PUR Conference. New Orleans, Louisiana. May 24, 1999.

147. "The Political Economy of Electric Restructuring In the South" Southeastern Electric Exchange, Rate Section Annual Conference. New Orleans, Louisiana. May 7, 1999.

148. "The Dynamics of Electric Restructuring in Louisiana." Joint Meeting of the American Association of Energy Engineers and the International Association of Facilities Managers. Metairie, Louisiana. April 29, 1999.

149. "The Implications of Electric Restructuring on Independent Oil and Gas Operations." Petroleum Technology Transfer Council Workshop: Electrical Power Cost Reduction Methods in Oil and Gas Field Operations. Lafayette, Louisiana, March 24, 1999.

150. "What's Happened to Electricity Restructuring in Louisiana?" Louisiana State University, Center for Energy Studies Industry Associates Meeting. March 22, 1999.

151. "A Short Course on Electric Restructuring." Central Louisiana Electric Company. Sales and Marketing Division. Mandeville, Louisiana, October 22, 1998.

152. "The Implications of Electric Restructuring on Independent Oil and Gas Operations." Petroleum Technology Transfer Council Workshop: Electrical Power Cost Reduction Methods in Oil and Gas Field Operations. Shreveport, Louisiana, October 13, 1998.

153. "How Will Utility Deregulation Affect Tourism." Louisiana Travel Promotion Association Annual Meeting, Alexandria, Louisiana. January 15, 1998.

154. "Reflections and Predictions on Electric Utility Restructuring in Louisiana." With Fred I. Denny. Louisiana State University, Center for Energy Studies Industry Associates Meeting. November 20, 1997.

155. "Electric Utility Restructuring in Louisiana." Hammond Chamber of Commerce, Hammond, Louisiana. October 30, 1997.

156. "Electric Utility Restructuring." Louisiana Association of Energy Engineers. Baton Rouge, Louisiana. September 11, 1997.

157. "Electric Utility Restructuring: Issues and Trends for Louisiana." Opelousas Chamber of Commerce, Opelousas, Louisiana. June 24, 1997.

158. "The Electric Utility Restructuring Debate In Louisiana: An Overview of the Issues." Annual Conference of the Public Affairs Research Council of Louisiana. Baton Rouge, Louisiana. March 25, 1997.

159. "Electric Restructuring: Louisiana Issues and Outlook for 1997." Louisiana State University, Center for Energy Studies Industry Associates Meeting, Baton Rouge, Louisiana, January 15, 1997.

160. "Restructuring the Electric Utility Industry." Louisiana Propane Gas Association Annual Meeting, Alexandria, Louisiana, December 12, 1996.

161. "Deregulating the Electric Utility Industry." Eighth Annual Economic Development Summit, Baton Rouge, Louisiana, November 21, 1996.

162. "Electric Utility Restructuring in Louisiana." Jennings Rotary Club, Jennings, Louisiana, November 19, 1996.

163. "Electric Utility Restructuring in Louisiana." Entergy Services, Transmission and Distribution Division, Energy Centre, New Orleans, Louisiana, September 12, 1996

164. "Electric Utility Restructuring" Louisiana Electric Cooperative Association, Baton Rouge, Louisiana, August 27, 1996.

165. "Electric Utility Restructuring -- Background and Overview." Louisiana Public Service Commission, Baton Rouge, Louisiana, August 14, 1996.

166. "Electric Utility Restructuring." Sunshine Rotary Club Meetings, Baton Rouge, Louisiana, August 8, 1996.

167. Roundtable Moderator, "Stakeholder Perspectives on Electric Utility Stranded Costs." Louisiana State University, Center for Energy Studies Seminar on Electric Utility Restructuring in Louisiana, Baton Rouge, May 29, 1996.

168. Panelist, "Deregulation and Competition." American Nuclear Society: Second Annual Joint Louisiana and Mississippi Section Meetings, Baton Rouge, Louisiana, April 20, 1996.

EXPERT WITNESS, LEGISLATIVE, AND PUBLIC TESTIMONY; EXPERT REPORTS, RECOMMENDATIONS, AND AFFIDAVITS

1. Expert Testimony. Case No. 9326 (2013). Before the Public Service Commission of Maryland. In the Matter of the Application of Baltimore Gas and Electric Company for Adjustments to its Electric and Gas Base Rates. Issues: Electric Reliability Investment ("ERI") initiatives, pro forma gas infrastructure proposal, tracker mechanisms, class cost of service study, revenue distribution, and rate design

2. Rulemaking Testimony. (2013). Before the Louisiana Tax Commission. Examination of Louisiana Assessors' Association Well Diameter Analysis, economic development policies regarding midstream assets and industrial development.

3. Expert Testimony. Case No. 9317 (2013). Before the Public Service Commission of Maryland. In the Matter of the Application of Delmarva Power & Light Company for Adjustments to its Retail Rates for the Distribution of Electric Energy. Direct, and Surrebuttal. Issues: Grid Resiliency Charge, tracker mechanisms, pipeline replacement, class cost of service study, revenue distribution, and rate design.

4. Expert Testimony. Case No. 9311 (2013). Before the Public Service Commission of Maryland. In the Matter of the Application of Potomac Electric Power Company for an Increase in its Retail Rates for the Distribution of Electric Energy. Direct, and Surrebuttal. Issues: Grid Resiliency Charge, tracker mechanisms, pipeline replacement, class cost of service study, revenue distribution, and rate design.

5. Expert Testimony. Docket No. 12AL-1268G (2013). Before the Public Utilities Commission of the State of Colorado. In the Matter of the Tariff Sheets Filed by Public Service Company of Colorado with Advice No. 830 – Gas. Answer. Issues: Pipeline System Integrity Adjustment, tracker mechanisms, pipeline replacement and leak rate comparisons.

6. Expert Testimony. BPU Docket No. EO12080721 (2013). Before the New Jersey Board of Public Utilities. In the Matter of the Public Service Electric & Gas Company for Approval of an Extension of Solar Generation Program. On the Behalf of the New Jersey Division of Rate Counsel. Direct, Rebuttal, Surrebuttal. Issues: solar energy market design, solar energy market conditions, solar energy program design and net economic benefits.

7. Expert Testimony. BPU Docket No. EO12080726 (2013). Before the New Jersey Board of Public Utilities. In the Matter of the Petition of Public Service Electric & Gas Company for Approval of a Solar Loan III Program. On the Behalf of the New Jersey Division of Rate Counsel. Direct, Rebuttal and Surrebuttal. Issues: solar energy market design, solar energy market conditions, solar energy program design.

8. Expert Testimony. BPU Docket No. EO11050314V. (2012). Before the New Jersey Board of Public Utilities. In the Matter of the Petition of Fishermen's Atlantic City Windfarm, LLC for the Approval of the State Waters Project and Authorizing Offshore Wind Renewable Energy Certificates. On the Behalf of the New Jersey Division of Rate Counsel. December 17, 2012. Issues: approval of offshore wind project and ratepayer financial support for the proposed project.

9. Expert Testimony. D.P.U. 12-25. (2012). Before the Massachusetts Department of Public Utilities. In the Matter of Bay State Gas Company d/b/a/ Columbia Gas Company of Massachusetts Request for Increase in Rates. On the Behalf of the Office of the Attorney General, Office of Ratepayer Advocacy. Issues: Target infrastructure replacement program rider, pipeline replacement and leak rate comparisons.

10. Expert Testimony. Docket Nos. UE-120436, et.al. (consolidated). (2012). Before the Washington Utilities and Transportation Commission. Washington Utilities and Transportation Commission v. Avista Corporation D/B/A Avista Utilities. On the Behalf of the Washington Attorney General, Office of the Public Counsel. Issues: Revenue Decoupling, lost revenues, tracker mechanisms, attrition adjustments.

11. Expert Testimony. Case No. 9286. (2012) Before the Public Service Commission of Maryland. In Re: Potomac Electric Power Company ("Pepco") General Rate Case. On the Behalf of the Maryland Office of the People's Counsel. Issues: Capital tracker mechanisms/reliability investment mechanisms, reliability issues, regulatory lag, class cost of service, revenue distribution, rate design.

12. Expert Testimony. Case No 9285. (2012) Before the Public Service Commission of Maryland. In Re: the Delmarva Power and Light Company General Rate Case. On the Behalf of the Maryland Office of the People's Counsel. Issues: Capital tracker mechanisms/reliability investment mechanisms, reliability issues, regulatory lag, class cost of service, revenue distribution, rate design.

13. Expert Testimony. Docket Nos. UE-110876 and UG-110877 (consolidated). (2012). Before the Washington Utilities and Transportation Commission. Washington Utilities and Transportation Commission v. Avista Corporation D/B/A Avista Utilities. On the Behalf of the Washington Attorney General, Office of the Public Counsel. Issues:

Revenue Decoupling, lost revenues, tracker mechanisms.

14. Expert Testimony. BPU Docket No. EO11050314V. (2012). Before the New Jersey Board of Public Utilities. In the Matter of the Petition of Fishermen's Atlantic City Windfarm, LLC for the Approval of the State Waters Project and Authorizing Offshore Wind Renewable Energy Certificates. On the Behalf of the New Jersey Division of Rate Counsel. February 3, 2012. Issues: approval of offshore wind project and ratepayer financial support for the proposed project.

15. Expert Testimony. Docket No. NG 0067. (2012). Before the Public Service Commission of Nebraska. In the Matter of the Application of SourceGas Distribution, LLC Approval of a General Rate Increase. On the Behalf of the Public Advocate. January 31, 2012. Issues: Revenue Decoupling, Customer Adjustments, Weather Normalization Adjustments, Class Cost of Service Study, Rate Design.

16. Expert Testimony. Docket No. G-04204A-11-0158. (2011). Before the Arizona Corporation Commission. On the Behalf of the Arizona Corporation Commission Staff. In the Matter of the Application of UNS Gas, Inc. for the Establishment of Just and Reasonable Rates and Charges Designed to Realize a Reasonable Rate of Return on the Fair Value of Its Arizona Properties. Issues: Revenue Decoupling; Class Cost of Service Modeling; Revenue Distribution; Rate Design.

17. Expert Testimony. Formal Case Number 1087. (2011). Before the Public Service Commission of the District of Columbia. On the Behalf of the Office of the People's Counsel of the District of Columbia. In the Matter of the Application of Potomac Electric Power Company for Authority to Increase Existing Retail Rates and Charges for Electric Distribution Service. Issues: Regulatory lag, ratemaking principles, reliability-related capital expenditure tracker proposals.

18. Expert Affidavit. Case No. 11-1364. (2011). *The State of Louisiana, the Louisiana Department of Environmental Quality, and the Louisiana Public Service Commission v. United States Environmental Protection Agency and Lisa P. Jackson.* Before the United States Court of Appeals for the District of Columbia Circuit. On the behalf of the State of Louisiana, the Louisiana Department of Environmental Quality, and the Louisiana Public Service Commission. Issues: Impacts of environmental costs on electric utilities, compliance requirements, investment cost of mitigation equipment, multi-area dispatch modeling and plant retirements.

19. Expert Affidavit. Docket No. EPA-HQ-OAR-2009-0491. (2011). Before the U.S. Environmental Protection Agency. Federal Implementation Plans: Interstate Transport of Fine Particulate Matter and Ozone and Correction of SIP Approvals. On the Behalf of the Louisiana Public Service Commission. Issues: Impacts of environmental costs on electric utilities, compliance requirements, investment cost of mitigation equipment, multi-area dispatch modeling and plant retirements.

20. Expert Testimony. Case No. 9296. (2011). Before the Maryland Public Service Commission. On the Behalf of the Maryland Office of People's Counsel. In the Matter of the Application of Washington Gas Light Company for Authority to Increase Existing

Rates and Charges and Revise its Terms and Conditions for Gas Service. Issues: Infrastructure Cost Recovery Rider; Class Cost of Service Modeling; Revenue Distribution; Rate Design.

21. Expert Testimony. Docket No. G-01551A-10-0458. (2011). Before the Arizona Corporation Commission. On the Behalf of the Arizona Corporation Commission Staff. In the Matter of the Application of Southwest Gas Corporation for the Establishment of Just and Reasonable Rates and Charges Designed to Realize A Reasonable Rate of Return on the Fair Value of its Properties throughout Arizona. Issues: Revenue Decoupling; Class Cost of Service Modeling; Revenue Distribution; Rate Design.

22. Expert Testimony. Docket No. 11-0280 and 11-0281. (2011). Before the Illinois Commerce Commission. On the Behalf of the Illinois Attorney General, the Citizens Utility Board, and the City of Chicago, Illinois. In re: Peoples Gas Light and Coke Company and North Shore Natural Gas Company. Issues: Revenue Decoupling and Rate Design. (Direct and Rebuttal)

23. Expert Testimony. D.P.U. 11-01. (2011). Before the Massachusetts Department of Public Utilities. On the Behalf of the Office of the Attorney General, Office of Ratepayer Advocacy. Petition of the Fitchburg Electric and Gas Company (Electric Division) for Approval of A General Increase in Electric Distribution Rates and Approval of a Revenue Decoupling Mechanism. Issues: Capital Cost Rider, Revenue Decoupling.

24. Expert Testimony. D.P.U. 11-02. (2011). Before the Massachusetts Department of Public Utilities. On the Behalf of the Office of the Attorney General, Office of Ratepayer Advocacy. Petition of the Fitchburg Electric and Gas Company (Gas Division) for Approval of A General Increase in Electric Distribution Rates and Approval of a Revenue Decoupling Mechanism. Issues: Pipeline Replacement Rider, Revenue Decoupling.

25. Expert Affidavit. Docket No. EL-11-13 (2011). Before the Federal Energy Regulatory Commission. Petition for Preliminary Ruling, Atlantic Grid Operations. On the Behalf of the New Jersey Division of Rate Counsel. Issues: Offshore wind generation development, offshore wind transmission development, ratemaking treatment of development costs, transmission development incentives.

26. Expert Opinion. Case No. CI06-195. (2011). Before the District Court of Jefferson County, Nebraska. On the Behalf of the City of Fairbury, Nebraska and Michael Beachler. In re: Endicott Clay Products Co. vs. City of Fairbury, Nebraska and Michael Beachler. Issues: rate design and ratemaking, time of use and time differentiated rate structures, empirical analysis of demand and usage trends for tariff eligibility requirements.

27. Expert Testimony. D.P.U. 10-114. (2010). Before the Massachusetts Department of Public Utilities. On the Behalf of the Office of the Attorney General, Office of Ratepayer Advocacy. Petition of the New England Gas Company for Approval of A General Increase in Electric Distribution Rates and Approval of a Revenue Decoupling Mechanism. Issues: infrastructure replacement rider.

28. Expert Testimony. D.P.U. 10-70. (2010). Before the Massachusetts Department of Public Utilities. Petition of the Western Massachusetts Electric Company for Approval of A General Increase in Electric Distribution Rates and Approval of a Revenue Decoupling Mechanism. On the Behalf of the Office of the Attorney General, Office of Ratepayer Advocacy. Issues: Revenue decoupling; infrastructure replacement rider; performance-based regulation; inflation adjustment mechanisms; and rate design.

29. Expert Testimony. G.U.D. Nos. 998 & 9992. (2010). Before the Texas Railroad Commission. In the Matter of the Rate Case Petition of Texas Gas Services, Inc. On the Behalf of the City of El Paso, Texas. Issues: Cost of service, revenue distribution, rate design, and weather normalization.

30. Expert Testimony. B.P.U Docket No. GR10030225. (2010). Before the New Jersey Board of Public Utilities. In the Matter of the Petition of New Jersey Natural Gas Company for Approval of Regional Greenhouse Gas Initiative Programs and Associated Cost Recovery Mechanisms Pursuant to N.J.S.A. 48:3-98.1. On the Behalf of the Department of the Public Advocate, Division of Rate Counsel. Issues: solar energy proposals, solar securitization issues, solar energy policy issues.

31. Expert Testimony. D.P.U. 10-55. (2010). Before the Massachusetts Department of Public Utilities. Investigation Into the Propriety of Proposed Tariff Changes for Boston Gas Company, Essex Gas Company, and Colonial Gas Company. (d./b./a. National Grid). On the Behalf of the Office of the Attorney General, Office of Ratepayer Advocacy. Issues: Revenue decoupling; pipeline-replacement rider; performance-based regulation; partial productivity factor estimates, inflation adjustment mechanisms; and rate design.

32. Expert Testimony. Cause No.43839. (2010). Before the Indiana Utility Regulatory Commission. In the Matter of Southern Indiana Gas and Electric Company d/b/a/ Vectren Energy Delivery of Indiana, Inc. (Vectren South-Electric). On the behalf of the Indiana Office of Utility Consumer Counselor (OUCC). Issues: revenue decoupling, variable production cost riders, gains on off-system sales, transmission cost riders.

33. Congressional Testimony. Before the United States Congress. (2010). U.S. House of Representatives, Committee on Natural Resources. Hearing on the Consolidated Land, Energy, and Aquatic Resources Act. June 30, 2010.

34. Expert Testimony. Before the City Counsel of El Paso, Texas; Public Utility Regulatory Board. (2010). On the Behalf of the City of El Paso. In Re: Rate Application of Texas Gas Services, Inc. Issues: class cost of service study (minimum system and zero intercept analysis), rate design proposals, weather normalization adjustment, and its cost of service adjustment clause, conservation adjustment clause proposals, and other cost tracker policy issues.

35. Expert Testimony. Docket 09-00183. (2010). Before the Tennessee Regulatory Authority. In the Matter of the Petition of Chattanooga Gas Company for a General Rate Increase, Implementation of the EnergySMART Conservation Programs, and Implementation of a Revenue Decoupling Mechanism. On the Behalf of Tennessee

Attorney General, Consumer Advocate & Protection Division. Issues: revenue decoupling and energy efficiency program review and cost effectiveness analysis.

36. Expert Testimony and Exhibits. Docket No. 10-240. (2010). Before the Louisiana Office of Conservation. In Re: Cadeville Gas Storage, LLC. On the Behalf of Cardinal Gas Storage, LLC. Issues: alternative uses and relative economic benefits of conversion of depleted hydrocarbon reservoir for natural gas storage purposes.

37. Expert Testimony. Docket No. 09505-EI. (2010). Before the Florida Public Service Commission. In Re: Review of Replacement Fuel Costs Associated with the February 26, 2008 outage on Florida Power & Light's Electrical System. On the Behalf of the Florida Office of Public Counsel for the Citizens of the State of Florida. Issues: Replacement costs for power outage, regulatory policy/generation development incentives, renewable and energy efficiency incentives.

38. Expert Testimony. Docket 09-00104. (2009). Before the Tennessee Regulatory Authority. In the Matter of the Petition of Piedmont Natural Gas Company, Inc. to Implement a Margin Decoupling Tracker Rider and Related Energy Efficiency and Conservation Programs. On the Behalf of the Tennessee Attorney General, Consumer Advocate & Protection Division. Issues: revenue decoupling, energy efficiency program review, weather normalization.

39. Expert Testimony. Docket Number NG-0060. (2009). Before the Nebraska Public Service Commission. In the Matter of SourceGas Distribution, LLC Approval for a General Rate Increase. On the Behalf of the Nebraska Public Advocate. October 29, 2009. Issues: revenue decoupling, inflation trackers, infrastructure replacement riders, customer adjustment rider, weather normalization rider, weather normalization adjustments, estimation of normal weather for ratemaking purposes.

40. Expert Report and Deposition. Before the 23rd Judicial District Court, Parish of Assumption, State of Louisiana. On the Behalf of Dow Hydrocarbons and Resources, Inc. September 1, 2009. (Deposition, November 23-24, 2009). Issues: replacement and repair costs for underground salt cavern hydrocarbon storage.

41. Expert Testimony. D.P.U. 09-39. Before the Massachusetts Department of Public Utilities. (2009). Investigation Into the Propriety of Proposed Tariff Changes for Massachusetts Electric Company and Nantucket Electric Company (d./b./a. National Grid). On the Behalf of the Office of the Attorney General, Office of Ratepayer Advocacy. Issues: Revenue decoupling; infrastructure rider; performance-based regulation; inflation adjustment mechanisms; revenue distribution; and rate design.

42. Expert Testimony. D.P.U. 09-30. Before the Massachusetts Department of Public Utilities. (2009). In the Matter of Bay State Gas Company Request for Increase in Rates. On the Behalf of the Office of the Attorney General, Office of Ratepayer Advocacy. Issues: Revenue decoupling; target infrastructure replacement program rider; revenue distribution; and rate design.

43. Expert Testimony. Docket EO09030249. (2009). Before the New Jersey Board of

Public Utilities. In the Matter of the Petition of Public Service Electric and Gas Company for Approval of a Solar Loan II Program and An Associated Cost Recovery Mechanism. On the Behalf of the Department of the Public Advocate, Division of Rate Counsel. Issues: solar energy market design, renewable portfolio standards, solar energy, and renewable financing/loan program design.

44. Expert Testimony. Docket EO0920097. (2009). Before the New Jersey Board of Public Utilities. In the Matter of the Verified Petition of Rockland Electric Company for Approval of an SREC-Based Financing Program and An Associated Cost Recovery Mechanism. On the Behalf of the Department of the Public Advocate, Division of Rate Counsel. Issues: solar energy market design; renewable energy portfolio standards; solar energy.

45. Expert Rebuttal Report. Civil Action No.: 2:07-CV-2165. (2009). Before the U.S. District Court, Western Division of Louisiana, Lake Charles Division. Prepared on the Behalf of the Transcontinental Pipeline Corporation. Issues: expropriation and industrial use of property.

46. Expert Testimony. Docket EO06100744. (2008). Before the New Jersey Board of Public Utilities. In the Matter of the Renewable Portfolio Standard – Amendments to the Minimum filing Requirements for Energy Efficiency, Renewable Energy, and Conservation Programs and For Electric Distribution Company Submittals of Filings in connection with Solar Financing (Atlantic City Electric Company). On the Behalf of the Department of the Public Advocate, Division of Rate Counsel. Issues: Solar energy market design; renewable energy portfolio standards; solar energy. (Rebuttal and Surrebuttal)

47. Expert Testimony. Docket EO08090840. (2008). Before the New Jersey Board of Public Utilities. In the Matter of the Renewable Portfolio Standard – Amendments to the Minimum filing Requirements for Energy Efficiency, Renewable Energy, and Conservation Programs and For Electric Distribution Company Submittals of Filings in connection with Solar Financing (Jersey Central Power & Light Company). On the Behalf of the Department of the Public Advocate, Division of Rate Counsel. Issues: Solar energy market design; renewable energy portfolio standards; solar energy. (Rebuttal and Surrebuttal)

48. Expert Testimony. Docket UG-080546. (2008). Before the Washington Utilities and Transportation Commission. On the Behalf of the Washington Attorney General (Public Counsel Section). Issues: Rate Design, Cost of Service, Revenue Decoupling, Weather Normalization.

49. Congressional Testimony. (2008). Senate Republican Conference: Panel on Offshore Drilling in the Restricted Areas of the Outer Continental Shelf. September 18, 2008.

50. Expert Testimony. Appeal Number 2007-125 and 2007-299. (2008). Before the Louisiana Tax Commission. On the Behalf of Jefferson Island Storage and Hub, LLC (AGL Resources). Issues: Valuation Methodologies, Underground Storage Valuation, LTC Guidelines and Policies, Public Purpose of Natural Gas Storage. July 15, 2008 and August 20, 2008.

51. Expert Testimony. Docket Number 07-057-13. (2008). Before the Utah Public Service Commission. In the Matter of the Application of Questar Gas Company to File a General Rate Case. On the Behalf of the Utah Committee of Consumer Services. Issues: Cost of Service, Rate Design. August 18, 2008 (Direct, Rebuttal, Surrebuttal).

52. Rulemaking Testimony. (2008). Before the Louisiana Tax Commission. Examination of Replacement Cost Tables, Depreciation and Useful Lives for Oil and Gas Properties. Chapter 9 (Oil and Gas Properties) Section. August 5, 2008.

53. Legislative Testimony. (2008). Examination of Proposal to Change Offshore Natural Gas Severance Taxes (HB 326 and Amendments). Joint Finance and Appropriations Committee of the Alabama Legislature. March 13, 2008.

54. Public Testimony. (2007). Issues in Environmental Regulation. Testimony before Gubernatorial Transition Committee on Environmental Regulation (Governor-Elect Bobby Jindal). December 17, 2007.

55. Public Testimony. (2007). Trends and Issues in Alternative Energy: Opportunities for Louisiana. Testimony before Gubernatorial Transition Committee on Natural Resources (Governor-Elect Bobby Jindal). December 13, 2007.

56. Expert Report and Recommendation: Docket Number S-30336 (2007). Before the Louisiana Public Service Commission. In re: Entergy Gulf States, Inc. Application for Approval of Advanced Metering Pilot Program. Issues: pilot program for demand response programs and advanced metering systems.

57. Expert Testimony. Docket EO07040278 (2007). Before the New Jersey Board of Public Utilities. In the Matter of the Petition of Public Service Electric & Gas Company for Approval of a Solar Energy Program and An Associated Cost Recovery Mechanism. On the Behalf of the Department of the Public Advocate, Division of Rate Counsel. Issues: renewable energy market development, solar energy development, SREC markets, rate impact analysis, cost recovery issues.

58. Expert Testimony: Docket Number 05-057-T01 (2007). Before the Utah Public Service Commission. In the Matter of: Joint Application of Questar Gas Company, the Division of Public Utilities, and Utah Clean Energy for Approval of the Conservation Enabling Tariff Adjustment Options and Accounting Orders. On the behalf of the Utah Committee of Consumer Services. Issues: Revenue Decoupling, Demand-side Management; Energy Efficiency policies. (Direct, Rebuttal, and Surrebuttal Testimony)

59. Expert Testimony (Non-sworn rulemaking testimony) Docket Number RR-2008, (2007). Before the Louisiana Tax Commission. In re: Commission Consideration of Amendment and/or Adoption of Tax Commission Real/Personal Property Rules and Regulations. Issues: Louisiana oil and natural gas production trends, appropriate cost measures for wells and subsurface property, economic lives and production decline curve trends.

60. Expert Report, Recommendation, and Proposed Rule: Docket Number R-29213 &

29213-A, ex parte, (2007). Before the Louisiana Public Service Commission. In re: In re: Investigation to determine if it is appropriate for LPSC jurisdictional electric utilities to provide and install time-based meters and communication devices for each of their customers which enable such customers to participate in time-based pricing rate schedules and other demand response programs. On the behalf of the Louisiana Public Service Commission Staff. Report and Recommendation. Issues: demand response programs, advanced meter systems, cost recovery issues, energy efficiency issues, regulatory issues.

61. Expert Report, Recommendation, and Proposed Rule: Docket Number R-29712, ex parte, (2007) Before the Louisiana Public Service Commission. In re: Investigation into the ratemaking and generation planning implications of nuclear construction in Louisiana. On the behalf of the Louisiana Public Service Commission Staff. Report and Recommendation. Issues: nuclear cost power plant development, generation planning issues, and cost recovery issues.

62. Expert Testimony, Case Number U-14893, (2006). Before the Michigan Public Service Commission. In the Matter of SEMCO Energy Gas Company for Authority to Redesign and Increase Its Rates for the Sale and Transportation of Natural Gas In its MPSC Division and for Other Relief. On the behalf of the Michigan Attorney General. Issues: Rate Design, revenue decoupling, financial analysis, demand-side management program and energy efficiency policy. (Direct and Rebuttal Testimony).

63. Expert Report, Recommendation, and Proposed Rule: Docket Number R-29380, ex parte, (2006). Before the Louisiana Public Service Commission. In re: An Investigation Into the Ratemaking and Generation Planning Implications of the U.S. EPA Clean Air Interstate Rule. On the behalf of the Louisiana Public Service Commission Staff. Report and Recommendation. Issues: environmental regulation and cost recovery; allowance allocations and air credit markets; ratepayer impacts of new environmental regulations.

64. Expert Affidavit Before the Louisiana Tax Commission (2006). On behalf of ANR Pipeline, Tennessee Gas Transmission and Southern Natural Gas Company. Issues: Competitive nature of interstate and intrastate transportation services.

65. Expert Affidavit Before the 19th Judicial District Court (2006). Suit Number 491, 453 Section 26. On behalf of Transcontinental Pipeline Corporation, et.al. Issues: Competitive nature of interstate and intrastate transportation services.

66. Expert Testimony: Docket Number 05-057-T01 (2006). Before the Utah Public Service Commission. In the Matter of: Joint Application of Questar Gas Company, the Division of Public Utilities, and Utah Clean Energy for Approval of the Conservation Enabling Tariff Adjustment Options and Accounting Orders. On the behalf of the Utah Committee of Consumer Services. Issues: Revenue Decoupling; Demand-side Management; Energy Efficiency policies. (Rebuttal and Supplemental Rebuttal Testimony)

67. Legislative Testimony (2006). Senate Committee on Natural Resources. Senate Bill 655 Regarding Remediation of Oil and Gas Sites, Legacy Lawsuits, and the Deterioration of State Drilling.

68. Expert Report: Rulemaking Docket (2005). Before the New Jersey Bureau of Public Utilities. In re: Proposed Rulemaking Changes Associated with New Jersey's Renewable Portfolio Standard. Expert Report. The Economic Impacts of New Jersey's Proposed Renewable Portfolio Standard. On behalf of the New Jersey Office of Ratepayer Advocate. Issues: Renewable Portfolio Standards, rate impacts, economic impacts, technology cost forecasts.

69. Expert Testimony: Docket Number 2005-191-E. (2005). Before the South Carolina Public Service Commission. On behalf of NewSouth Energy LLC. In re: General Investigation Examining the Development of RFP Rules for Electric Utilities. Issues: Competitive bidding; merchant development. (Direct and Rebuttal Testimony).

70. Expert Testimony: Docket No. 05-UA-323. (2005). Before the Mississippi Public Service Commission. On the behalf of Calpine Corporation. In re: Entergy Mississippi's Proposed Acquisition of the Attala Generation Facility. Issues: Asset acquisition; merchant power development; competitive bidding.

71. Expert Testimony: Docket Number 050045-EI and 050188-EI. (2005). Before the Florida Public Service Commission. On the behalf of the Citizens of the State of Florida. In re: Petition for Rate Increase by Florida Power & Light Company. Issues: Load forecasting; O&M forecasting and benchmarking; incentive returns/regulation.

72. Expert Testimony (non-sworn, rulemaking): Comments on Decreased Drilling Activities in Louisiana and the Role of Incentives. (2005). Louisiana Mineral Board Monthly Docket and Lease Sale. July 13, 2005

73. Legislative Testimony (2005). Background and Impact of LNG Facilities on Louisiana. Joint Meeting of Senate and House Natural Resources Committee. Louisiana Legislature. May 19, 2005.

74. Public Testimony. Docket No. U-21453. (2005). Technical Conference before the Louisiana Public Service Commission on an Investigation for a Limited Industrial Retail Choice Plan.

75. Expert Testimony: Docket No. 2003-K-1876. (2005). On Behalf of Columbia Gas Transmission. Expert Testimony on the Competitive Market Structure for Gas Transportation Service in Ohio. Before the Ohio Board of Tax Appeals.

76. Expert Report and Testimony: Docket No. 99-4490-J, *Lafayette City-Parish Consolidated Government, et. al. v. Entergy Gulf States Utilities, Inc. et. al.* (2005, 2006). On behalf of the City of Lafayette, Louisiana and the Lafayette Utilities Services. Expert Rebuttal Report of the Harborfront Consulting Group Valuation Analysis of the LUS Expropriation. Filed before 15th Judicial District Court, Lafayette, Louisiana.

77. Expert Testimony: ANR Pipeline Company v. Louisiana Tax Commission (2005), Number 468,417 Section 22, 19th Judicial District Court, Parish of East Baton Rouge, State of Louisiana Consolidated with Docket Numbers: 480,159; 489,776;480,160;

480,161; 480,162; 480,163; 480,373; 489,776; 489,777; 489,778;489,779; 489,780; 489,803; 491,530; 491,744; 491,745; 491,746; 491,912;503,466; 503,468; 503,469; 503,470; 515,414; 515,415; and 515,416. In re: Market structure issues and competitive implications of tax differentials and valuation methods in natural gas transportation markets for interstate and intrastate pipelines.

78. Expert Report and Recommendation: Docket No. U-27159. (2004). On Behalf of the Louisiana Public Service Commission Staff. Expert Report on Overcharges Assessed by Network Operator Services, Inc. Before the Louisiana Public Service Commission.

79. Expert Testimony: Docket Number 2004-178-E. (2004). Before the South Carolina Public Service Commission. On behalf of Columbia Energy LLC. In re: Rate Increase Request of South Carolina Electric and Gas. (Direct and Surrebuttal Testimony)

80. Expert Testimony: Docket Number 040001-EI. (2004). Before the Florida Public Service Commission. On behalf of Power Manufacturing Systems LLC, Thomas K. Churbuck, and the Florida Industrial Power Users Group. In re: Fuel Adjustment Proceedings; Request for Approval of New Purchase Power Agreements. Company examined: Florida Power & Light Company.

81. Expert Affidavit: Docket Number 27363. (2004). Before the Public Utilities Commission of Texas. Joint Affidavit on Behalf of the Cities of Texas and the Staff of the Public Utilities Commission of Texas Regarding Certified Issues. In Re: Application of Valor Telecommunications, L.P. For Authority to Establish Extended Local Calling Service (ELCS) Surcharges For Recovery of ELCS Surcharge.

82. Expert Report and Testimony. Docket 1997-4665-PV, 1998-4206-PV, 1999-7380-PV, 2000-5958-PV, 2001-6039-PV, 2002-64680-PV, 2003-6231-PV. (2003) Before the Kansas Board of Tax Appeals. (2003). In the Matter of the Appeals of CIG Field Services Company from orders of the Division of Property Valuation. On the Behalf of CIG Field Services. Issues: the competitive nature of natural gas gathering in Kansas.

83. Expert Report and Testimony: Docket Number U-22407. Before the Louisiana Public Service Commission (2002). On the Behalf of the Louisiana Public Service Commission Staff. Company examined: Louisiana Gas Services, Inc. Issues: Purchased Gas Acquisition audit, fuel procurement and planning practices.

84. Expert Testimony: Docket Number 000824-EI. Before the Florida Public Service Commission. (2002). On the Behalf of the Citizens of the State of Florida. Company examined: Florida Power Corporation. Issues: Load Forecasts and Billing Determinants for the Projected Test Year.

85. Public Testimony: Louisiana Board of Commerce and Industry (2001). Testimony on the Economic Impacts of Merchant Power Generation.

86. Expert Testimony: Docket Number 24468. (2001). On the Behalf of the Texas Office of Public Utility Counsel. Public Utility Commission of Texas Staff's Petition to Determine Readiness for Retail Competition in the Portion of Texas Within the Southwest Power

Pool. Company examined: AEP-SWEPCO.

87. Expert Report. (2001) On Behalf of David Liou and Pacific Richland Products, Inc. to Review Cogeneration Issues Associated with Dupont Dow Elastomers, L.L.C. (DDE) and the Dow Chemical Company (Dow).

88. Expert Testimony: Docket Number 01-1049, Docket Number 01-3001. (2001) On behalf the Nevada Office of Attorney General, Bureau of Consumer Protection. Petition of Central Telephone Company-Nevada D/b/a Sprint of Nevada and Sprint Communications L.P. for Review and Approval of Proposed Revised Performance Measures and Review and Approval of Performance Measurement Incentive Plans. Before the Public Utilities Commission of Nevada.

89. Expert Affidavit: Multiple Dockets (2001). Before the Louisiana Tax Commission. On the Behalf of Louisiana Interstate Pipeline Companies. Testimony on the Competitive Nature of Natural Gas Transportation Services in Louisiana.

90. Expert Affidavit before the Federal District Court, Middle District of Louisiana (2001). Issues: Competitive Nature of the Natural Gas Transportation Market in Louisiana. On behalf of a Consortium of Interstate Natural Gas Transportation Companies.

91. Public Testimony: Louisiana Board of Commerce and Industry (2001). Testimony on the Economic and Ratepayer Benefits of Merchant Power Generation and Issues Associated with Tax Incentives on Merchant Power Generation and Transmission.

92. Expert Testimony: Docket Number 01-1048 (2001). Before the Public Utilities Commission of Nevada. On the Behalf of the Nevada Office of the Attorney General, Bureau of Consumer Protection. Company analyzed: Nevada Bell Telephone Company. Issues: Statistical Issues Associated with Performance Incentive Plans.

93. Expert Testimony: Docket 22351 (2001). Before the Public Utility Commission of Texas. On the Behalf of the City of Amarillo. Company analyzed: Southwestern Public Service Company. Issues: Unbundled cost of service, affiliate transactions, load forecasting.

94. Expert Testimony: Docket 991779-EI (2000). Before the Florida Public Service Commission. On the Behalf of the Citizens of the State of Florida. Companies analyzed: Florida Power & Light Company; Florida Power Corporation; Tampa Electric Company; and Gulf Power Company. Issues: Competitive Nature of Wholesale Markets, Regional Power Markets, and Regulatory Treatment of Incentive Returns on Gains from Economic Energy Sales.

95. Expert Testimony: Docket 990001-EI (1999). Before the Florida Public Service Commission. On the Behalf of the Citizens of the State of Florida. Companies analyzed: Florida Power & Light Company; Florida Power Corporation; Tampa Electric Company; and Gulf Power Company. Issues: Regulatory Treatment of Incentive Returns on Gains from Economic Energy Sales.

96. Expert Testimony: Docket 950495-WS (1996). Before the Florida Public Service Commission. On the Behalf of the Citizens of the State of Florida. Company analyzed: Southern States Utilities, Inc. Issues: Revenue Repression Adjustment, Residential and Commercial Demand for Water Service.

97. Legislative Testimony. Louisiana House of Representatives, Special Subcommittee on Utility Deregulation. (1997). On Behalf of the Louisiana Public Service Commission Staff. Issue: Electric Restructuring.

98. Expert Testimony: Docket 940448-EG -- 940551-EG (1994). Before the Florida Public Service Commission. On the Behalf of the Legal Environmental Assistance Foundation. Companies analyzed: Florida Power & Light Company; Florida Power Corporation; Tampa Electric Company; and Gulf Power Company. Issues: Comparison of Forecasted Cost-Effective Conservation Potentials for Florida.

99. Expert Testimony: Docket 920260-TL, (1993). Before the Florida Public Service Commission. On the Behalf of the Florida Public Service Commission Staff. Company analyzed: BellSouth Communications, Inc. Issues: Telephone Demand Forecasts and Empirical Estimates of the Price Elasticity of Demand for Telecommunication Services.

100. Expert Testimony: Docket 920188-TL, (1992). Before the Florida Public Service Commission. On the Behalf of the Florida Public Service Commission Staff. Company analyzed: GTE-Florida. Issues: Telephone Demand Forecasts and Empirical Estimates of the Price Elasticity of Demand for Telecommunication Services.

REFEREE AND EDITORIAL APPOINTMENTS

Referee, 2010-Current, *Economics of Energy & Environmental Policy*
Referee, 1995-Current, *Energy Journal*
Contributing Editor, 2000-2005, *Oil, Gas and Energy Quarterly*
Referee, 2005, *Energy Policy*
Referee, 2004, *Southern Economic Journal*
Referee, 2002, *Resource & Energy Economics*
Committee Member, IAEE/USAEE Student Paper Scholarship Award Committee, 2003

PROPOSAL TECHNICAL REVIEWER

California Energy Commission, Public Interest Energy Research (PIER) Program (1999).

PROFESSIONAL ASSOCIATIONS

American Economic Association, American Statistical Association, Southern Economic Association, Western Economic Association, International Association of Energy Economists (IAEE), Unites States Association of Energy Economics and the National Association for Business Economics (NABE).

HONORS AND AWARDS

National Association of Regulatory Utility Commissioners (NARUC). Best Paper Award for papers published in the *Journal of Applied Regulation* (2004).

Baton Rouge Business Report, Selected as "Top 40 Under 40" (2003).

Omicron Delta Epsilon (1992-Current)

Interstate Oil and Gas Compact Commission (IOGCC) "Best Practice" Award for Research on the Economic Impact of Oil and Gas Activities on State Leases for the Louisiana Department of Natural Resources (2003).

Distinguished Research Award, Academy of Legal, Ethical and Regulatory Issues, Allied Academics (2002).

Florida Public Service Commission, Staff Excellence Award for Assistance in the Analysis of Local Exchange Competition Legislation (1995).

TEACHING EXPERIENCE

Energy and the Environment (Survey Course)
Principles of Microeconomic Theory
Principles of Macroeconomic Theory

Lecturer, Environmental Management and Permitting. Lecture in Natural Gas Industry, LNG and Markets.

Lecturer, Electric Power Industry Environmental Issues, Field Course on Energy and the Environment. (Dept of Environmental Studies).

Lecturer, Electric Power Industry Trends, Principles Course in Power Engineering (Dept. of Electric Engineering).

Lecturer, LSU Honors College, Senior Course on "Society and the Coast."

Continuing Education. Electric Power Industry Restructuring for Energy Professionals.

"The Gulf Coast Energy Situation: Outlook for Production and Consumption." Educational Course and Lecture Prepared for the Foundation for American Communications and the Society for Professional Journalists, New Orleans, LA, December 2, 2004

"The Impact of Hurricane Katrina on Louisiana's Energy Infrastructure and National Energy Markets." Educational Course and Lecture Prepared for the Foundation for American Communications and the Society for Professional Journalists, Houston, TX, September 13, 2005.

"Forecasting for Regulators: Current Issues and Trends in the Use of Forecasts, Statistical, and Empirical Analyses in Energy Regulation." Instructional Course for State Regulatory

Commission Staff. Institute of Public Utilities, Kellogg Center, Michigan State University. July 8-9, 2010.

"Regulatory and Ratemaking Issues with Cost and Revenue Trackers." Michigan State University, Institute of Public Utilities. Advanced Regulatory Studies Program. September 29, 2010.

"Demand Modeling and Forecasting for Regulators." Michigan State University, Institute of Public Utilities. Advanced Regulatory Studies Program. September 30, 2010.

"Demand Modeling and Forecasting for Regulators." Michigan State University, Institute of Public Utilities, Forecasting Workshop, Charleston, SC. March 7-9, 2011.

"Regulatory and Cost Recovery Approaches for Smart Grid Applications." Michigan State University, Institute of Public Utilities, Smart Grid Workshop for Regulators. Charleston, SC. March 7-11, 2011.

"Regulatory and Ratemaking Issues Associated with Cost and Expense Adjustment Mechanisms." Michigan State University, Institute of Public Utilities, Advanced Regulatory Studies Program. Lansing, Michigan. September 28, 2011.

"Utility Incentives, Decoupling, and Renewable Energy Programs." Michigan State University, Institute of Public Utilities, Advanced Regulatory Studies Program. Lansing, Michigan. September 29, 2011.

"Regulatory and Cost Recovery Approaches for Smart Grid Applications." Michigan State University, Institute of Public Utilities, Smart Grid Workshop for Regulators. Charleston, SC. March 6-8, 2012.

"Traditional and Incentive Ratemaking Workshop." New Mexico Public Utilities Commission Staff. Santa Fe, NM October 18, 2012.

"Traditional and Incentive Ratemaking Workshop." New Jersey Board of Public Utilities Staff. Newark, NJ. March 1, 2013.

THESIS/DISSERTATIONS COMMITTEES

Active:
2 Thesis Committee Memberships (Environmental Studies)
1 Ph.D. Dissertation Committee (Economics)

Completed:
6 Thesis Committee Memberships (Environmental Studies, Geography)
4 Doctoral Committee Memberships (Information Systems & Decision Sciences, Agricultural and Resource Economics, Economics, Education and Workforce Development).
2 Doctoral Examination Committee Membership (Information Systems & Decision Sciences, Education and Workforce Development)
1 Senior Honors Thesis (Journalism, Loyola University)

LSU SERVICE AND COMMITTEE MEMBERSHIPS

Co-Director/Steering Committee Member, LSU Coastal Marine Institute (2009-Current).

CES Promotion Committee, Division of Radiation Safety (2006).

Search Committee Chair (2006), Research Associate 4 Position.

Search Committee Member (2005), Research Associate 4 Position.

Search Committee Member (2005), CES Communications Manager.

LSU Graduate Research Faculty, Associate Member (1997-2004); Full Member (2004-2010); Affiliate Member with Full Directional Rights (2011-current).

LSU Faculty Senate (2003-2006).

Conference Coordinator. (2005-Current) Center for Energy Studies Conference on Alternative Energy.

LSU CES/SCE Public Art Selection Committee (2003-2005).

Conference Coordinator. Center for Energy Studies Annual Energy Conference/Summit. (2003-Current).

Conference Coordinator. Center for Energy Studies Seminar Series on Electric Utility Restructuring and Wholesale Competition. (1996-2003).

Co-Chairman, Review Committee, Louisiana Port Construction and Development Priority Program Rules and Regulations, On Behalf of the LSU Ports and Waterways Institute. (1997).

LSU Main Campus Cogeneration/Turbine Project, (1999-2000).

LSU InterCollege Environmental Cooperative. (1999-2001).

LSU Faculty Senate Committee on Public Relations (1997-1999).

LSU Faculty Senate Committee on Student Retention and Recruitment (1999-2003).

PROFESSIONAL SERVICE

Advisor (2008). National Association of Regulatory Utility Commissioners ("NARUC"). Study Committee on the Impact of Executive Drilling Moratoria on Federal Lands.

Steering Committee Member, Louisiana Representative (2008-Current). Southeast Agriculture & Forestry Energy Resources Alliance. Southern Policies Growth Board.

Advisor (2007-Current). National Association of State Utility Consumer Advocates ("NASUCA"), Natural Gas Committee.

Program Committee Chairman (2007-2008). U.S. Association of Energy Economics ("USAEE") Annual Conference, New Orleans, LA

Finance Committee Chairman (2007-2008). USAEE Annual Conference, New Orleans, LA

Committee Member (2006), International Association for Energy Economics ("IAEE") Nominating Committee.

Founding President (2005-2007) Louisiana Chapter, USAEE.

Secretary (2001) Houston Chapter, USAEE.

Advisor, Louisiana LNG Buyers/Developers Summit, Office of the Governor/Louisiana Department of Economic Development/Louisiana Department of Natural Resources, and Greater New Orleans, Inc. (2004).

Table of Schedules

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Company's Proposed Adjustment 26
Revenue Requirement

2013 Forecasted Reliability Closings ($ thousands)		
Rate Base		
Plant in Service		
Reliability Closings January 2013-December 2013	$	74,957
Retirements January 2013-December 2013	$	(4,950)
Adjustment to Plant in Service	$	70,007
Depreciation Reserve		
Retirements January 2013-December 2013	$	(4,950)
Depreciation Expense	$	917
Adjustment to Depreciation Reserve	$	(4,033)
Net Plant	$	74,040
Deferred Taxes	$	(7,246)
Total Rate Base	$	66,794
Revenue Requirement	$	10,438

Source: Jay C. Ziminsky, Direct Testimony, Schedule (JCZ)-25 and Schedule (JCZ)-1, p. 2.

Historic SAIDI and SAIFI and Performance Relative to PSC Docket No. 50 Benchmark

	2008	2009	2010	2011	2012
SAIDI	213	190	199	192	146
SAIFI	1.47	1.35	1.47	1.41	1.14
Improvement/(Decline)					
SAIDI		11%	-5%	4%	24%
SAIFI		8%	-9%	4%	19%
DE Benchmark[1]					
SAIDI	295	295	295	295	295
SAIDI Performance Relative to Benchmark - Improvement	28%	36%	33%	35%	51%

[1]SAIDI Benchmark set as a result of Delaware Administrative Code Title 26 Section 7 and the Commission's Decision in PSC Regulation Docket No. 50, Order 7725.
Source: Company's Response to Data Request PSC-CP-6; PSC Regulation Docket No. 50, Order 7725, Exhibit A, p. 10.

Historic vs. Projected Capital Expenditures

Witness: Dismukes
Docket No. 13-115
Schedule DED-3
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($ thousands)	Actual									
	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012
Customer Driven	$ 16,868	$ 20,817	$ 19,188	$ 23,148	$ 23,313	$ 18,169	$ 11,151	$ 14,260	$ 9,602	$ 12,628
Reliability	15,527	18,105	12,420	14,592	15,738	23,999	27,705	30,965	40,957	64,095
Load	8,024	7,286	5,501	4,858	1,407	4,728	13,386	6,431	1,027	2,798
TOTAL	$ 40,420	$ 46,208	$ 37,109	$ 42,598	$ 40,459	$ 46,896	$ 52,242	$ 51,656	$ 51,585	$ 79,521
									Total	$ 488,694
			5-Year Total 2003 to 2007		$ 206,793			**5-Year Total 2008 to 2012**		$ 281,901
Reliability	$ 15,527	$ 18,105	$ 12,420	$ 14,592	$ 15,738	$ 23,999	$ 27,705	$ 30,965	$ 40,957	$ 64,095
Total Investment	$ 40,420	$ 46,208	$ 37,109	$ 42,598	$ 40,459	$ 46,896	$ 52,242	$ 51,656	$ 51,585	$ 79,521
% of Investment	38.42%	39.18%	33.47%	34.25%	38.90%	51.17%	53.03%	59.94%	79.40%	80.60%
			5-Year Total 2003 to 2007		$ 76,382			**5-Year Total 2008 to 2012**		$ 187,722
					36.94%					66.59%

Historic vs. Projected Capital Expenditures

($ thousands)	Projected 2013	2014	2015	2016	2017
Customer Driven	$ 12,105	$ 11,891	$ 12,136	$ 12,604	$ 12,950
Reliability	71,414	58,911	59,233	60,274	59,250
Load	4,308	6,135	4,309	4,483	7,408
TOTAL	$ 87,827	$ 76,937	$ 75,677	$ 77,361	$ 79,608
				5-Year Total	$ 397,410
Reliability	$ 71,414	$ 58,911	$ 59,233	$ 60,274	$ 59,250
Total Investment	$ 87,827	$ 76,937	$ 75,677	$ 77,361	$ 79,608
% of Investment	81.31%	76.57%	78.27%	77.91%	74.43%
				5-Year Total	$ 309,081
					77.77%

Source: Company's Response to Data Request AG-GEN-1, Attachments A and B.

Comparison of Delmarva's Distribution Capital Budget to Actual Expenditures

Witness: Dismukes
Docket No. 13-115
Schedule DED-4
Page 1 of 1

($ thousands)	2007	2008	2009	2010	2011	2012
Capital Budget ($)						
Distribution						
Customer Driven	$ 22,490	$ 23,345	$ 21,589	$ 14,803	$ 12,265	$ 11,879
Reliability	12,583	26,308	24,711	32,199	41,672	60,079
Load	2,686	4,723	12,265	6,445	1,461	2,720
Total	**$ 37,759**	**$ 54,377**	**$ 58,565**	**$ 53,448**	**$ 55,398**	**$ 74,678**
Capital Actual ($)						
Distribution						
Customer Driven	$ 23,313	$ 18,169	$ 11,151	$ 14,260	$ 9,602	$ 12,628
Reliability	15,738	23,999	27,705	30,965	40,957	64,095
Load	1,407	4,728	13,386	6,431	1,027	2,798
Total	**$ 40,459**	**$ 46,896**	**$ 52,242**	**$ 51,656**	**$ 51,585**	**$ 79,521**
Percent Difference (%)						
Customer Driven	3.7%	-22.2%	-48.3%	-3.7%	-21.7%	6.3%
Reliability	25.1%	-8.8%	12.1%	-3.8%	-1.7%	6.7%
Load	-47.6%	0.1%	9.1%	-0.2%	-29.8%	2.9%
Total	**7.2%**	**-13.8%**	**-10.8%**	**-3.4%**	**-6.9%**	**6.5%**

Source: Company's Response to Data Request AG-GEN-1, Attachments A and C.

Budget to Actual Reliability Enhancement Plan[1]

Witness: Dismukes
Docket No. 13-115
Schedule DED-5
Page 1 of 3

Project	Sub-Project	Short Description	2011 Budget	2011 Actual as of 12/31/11	2011 Variance between Budget & Actual	2012 Budget	2012 Actual as of 12/31/12	2012 Variance between Budget & Actual	2013 Budget	2014 Budget	2015 Budget	2016 Budget	2017 Budget
Priority Feeder Upgrades										$5,008,191	$5,074,711	$5,023,813	$5,149,406
	UDLBRM4MF	Millsboro - Priority Circuit Improvement	$481,869	$1,361,055	182.5%	$1,494,110	$795,059	-46.8%	$2,501,875				
	UDLBRM4MK	Millsboro Priority Feeder Rebuild											
	UDLNRM4CF	Christiana - Priority Ckt Improvement	1,512,906	1,334,564	-11.8%	2,315,615	5,037,261	117.5%	2,538,288				
	UDLNRM4CK	Priority Feeder Rebuild: Christiana	721,017	209,958	-70.9%								
SUBTOTAL			$2,715,792	$2,905,577	7.0%	$3,809,725	$5,832,319	53.1%	$5,040,163	$5,008,191	$5,074,711	$5,023,813	$5,149,406
Underground Residential Distribution Cable Upgrades (URD)										$5,041,317	$5,080,518	$5,130,351	$5,173,937
	UDLBRM4MC	Millsboro - Replace Deteriorated URD Cable	$636,492	$759,646	19.3%	$751,172	$929,715	23.8%	$678,281				
	UDLBRM4MD	Millsboro - Planned URD Cable Replacement	1,200,000	2,004,031	67.0%	2,536,257	3,148,970	24.2%	1,776,909				
	UDLNRM4CC	Christiana - Replace Deteriorated URD Cable	961,105	1,073,832	11.7%	1,005,986	703,978	-30.0%	903,213				
	UDLNRM4CD	Christiana - Planned URD Cable Replacement				1,464,830	891,918	-39.1%	1,617,641				
	UDLNRM5CA	IR: Christiana - URD Infrastructure Replacements											
SUBTOTAL			$2,797,597	$3,837,509	37.2%	$5,758,245	$5,674,580	-1.5%	$4,976,044	$5,041,317	$5,080,518	$5,130,351	$5,173,937
Distribution Automation										$5,645,946	$7,402,598	$7,865,544	$8,076,344
	UDLBRDA1D	Distribution Automation - Bay DE	$570,727	$1,063,871	86.4%	$751,526	$397,950	-47.0%	$ -				
	UDSBRDA1D	Substation Distribution Automation Bay DE	437,987	200,647	-54.2%	463,469	924,674	99.5%	17,795				
	UOIBRASRD	Install ASR Computer: Bay DE; UF Install ASR Computer	144,908	2,555	-98.2%	132,725	121,397	-8.5%	7,843				
	UDLNRDA1C	Distribution Automation: Christiana District	1,045,169		-100.0%	1,036,068	184,726	-82.2%	1,508,748				
	UDSNRD8MD	Scada/RTU Upgrade NC DE Dist Sub				188,184	57,605	-69.4%	304,054				
	UDSNRDA1C	Distribution Automation: Christiana Substations	389,750	154,396	-60.4%	1,453,506	3,363,047	131.4%	823,380				
	UOINRASRD	Install ASR Computer: NC DE	144,908	79,502	-45.1%	187,498	167,057	-10.9%	223,254				
	UORBOBR1M	MI Comm Work - Collector to Data Network	441,936	88,494	-80.0%	271,455	64,175	-76.4%					
	UORBODA1M	Millsboro Comm Work - Install Radios in Line Equip	324,168	57,591	-82.2%	263,663	(12,552)	-104.8%					
	UORBORBSM	BBW Base Station - Install Millsboro	266,570	62,419	-76.6%	358,121	14,964	-95.8%	168,270				
	UORBORBTM	Millsboro Comm Work - Upgr Radios in Line Equip											
	UORBORCPM	Millsboro: Install Radio Control for Cap Contrl							19,270				
	UORBORSSM	Millsboro Sub Subscriber - BBW	201,659		-100.0%	272,775		-100.0%	145,735				
	UORNOBR1C	CH Comm Work - Collector to Data Network	375,928	196,004	-47.9%	258,206	286,224	10.9%	313,987				
	UORNODA1C	Christiana Comm Work - Install Radios in Line Equipment	222,709	46,907	-78.9%	429,811	173,459	-59.6%	437,553				
	UORNORBSC	BBW Base Station - Install Christiana	234,210	101,423	-56.7%	254,789	32,669	-87.2%	314,066				
	UORNORBTC	Christiana Comm Work: Upgrade Radios in Line Equip											
	UORNORCPC	Install Radio Control for Cap Cntrl-Christiana											
	UORNORSSC	Christiana - Sub Subscriber - BBW	202,270		-100.0%	439,608	114,852	-73.9%	330,325				
SUBTOTAL			$5,002,899	$2,053,809	-58.9%	$6,761,404	$5,890,246	-12.9%	$4,614,290	$5,645,946	$7,402,598	$7,865,544	$8,076,344

[1]See response to AG-REL-1(b)2, which states that AG-GEN-1 Attachment D is REP-only expenditures.

Budget to Actual Reliability Enhancement Plan[1]

Witness: Dismukes
Docket No. 13-115
Schedule DED-5
Page 2 of 3

Project	Sub-Progect	Short Description	2011 Budget	2011 Actual as of 12/31/11	2011 Variance between Budget & Actual	2012 Budget	2012 Actual as of 12/31/12	2012 Variance between Budget & Actual	2013 Budget	2014 Budget	2015 Budget	2016 Budget	2017 Budget
Feeder Reliability Improvements													
	UDLNRM4CK	Priority Feeder Rebuild: Christiana	$ -	$ -		$ -	$ -		$ -	$10,873,448	$13,025,930	$13,168,462	$13,497,673
	UDLBRM63M	Millsboro: Feeder Reliability Improvement	583,484	627,540	7.6%	2,568,671	2,647,888	3.1%	4,324,509				
	UDLNRM63C	Christiana Feeder Reliability Improvements	2,142,216	840,003	-60.8%	2,803,236	2,182,214	-22.2%	6,057,151				
SUBTOTAL			$2,725,700	$1,467,543	-46.2%	$5,371,907	$4,830,102	-10.1%	$10,381,760	$10,873,448	$13,025,930	$13,168,462	$13,497,673
Substation Reliability Improvements													
	UDSBRM61D	Bay - DE Sub Comprehensive Reliability Impvts	$ -	$ -		$1,505,615	$ -	-100.0%	$ -	$4,131,566	$3,865,015	$4,219,658	$5,541,917
	UDSNRM61D	NC - DE Sub Comprehensive Reliability Impvts; NC - DE Sub Comprehensive Reliability Impvts				1,575,271	1,982,713	25.9%					
	UDSBRD9SF	IR: Millsboro Sub - T1 Replacement							1,466,838				
	UDSBRD9SG	IR: Nr Seaford Sub - T1 & T2 Replacement[2]							282,050				
	UDSBRD9SJ	IR: Kent Sub - T2 Replacement											
	UDSBRD9SL	IR: Bethany Sub - T2 Replacement											
	UDSBRM61D	Bay - DE Sub Comprehensive Reliability Impvts											
	UDSNRD8KD	DPL DE - Switchgear replacements											
	UDSNRD9KA	Milford Crossroads Sub - Switchgear replacements							1,818,832				
	UDSNRD9KB	Bear Sub - Switchgear replacements							1,699,116				
	UDSNRD9KC	Naamans Sub - Switchgear replacements											
	UDSNRD9KD	Mermaid Sub - Switchgear replacements											
	UDSNRD9KE	West Wilmington Sub - Switchgear replacements											
	UDSNRD9KF	Churchmans Sub - Switchgear replacements											
	UDSNRD9KG	Milltown Sub - Switchgear replacements											
	UDSNRD9KH	Sunset Lake Sub - Switchgear replacements											
	UDSNRD9KI	Tallyville Sub - Switchgear replacements											
	UDSNRM61D	NC - DE Sub Comprehensive Reliability Impvts							547,708				
SUBTOTAL			$ -	$ -		$3,080,886	$1,982,713	-35.6%	$5,814,544	$4,131,566	$3,865,015	$4,219,658	$5,541,917
Conversions													
	UDLBRM8BA	Greenwood: 4-25kV Conversion	$ -	$ -		$ -	$ -		$745,726	$ -	$ -	$ -	$ -
	UDLBRM8BB	Wyoming-Convert to 25kV Cir 2233 (Phase II)							695,797				
SUBTOTAL			$ -	$ -		$ -	$ -		$1,441,523	$ -	$ -	$ -	$ -

[1]See response to AG-REL-1(b)2, which states that AG-GEN-1 Attachment D is REP-only expenditures.
[2]Not included in Pro Forma Adjustment 26.

Budget to Actual Reliability Enhancement Plan[1]

Witness: Dismukes
Docket No. 13-115
Schedule DED-5
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Project	Sub-Progect	Short Description	2011 Budget	2011 Actual as of 12/31/11	2011 Variance between Budget & Actual	2012 Budget	2012 Actual as of 12/31/12	2012 Variance between Budget & Actual	2013 Budget	2014 Budget	2015 Budget	2016 Budget	2017 Budget
Feeder Load Relief										$5,627,493	$3,797,420	$3,967,610	$6,879,880
	UDLBLBR1	Lakeside: Construct 2 New Feeders	$ -	$ -		$ -	$ -		$ -				
	UDLBLFP2	Five Points - Construct New Feeder											
	UDLBLM7M	Future Projects Dist Line Millsboro											
	UDLBLM7M	Millsboro - Feeder Load Relief	711,702	458,271	-35.6%	1,355,764	886,425	-34.6%	528,992				
	UDLBLM7M.1	Millsboro - Distribution VAR Correction											
	UDLBLM7M.13	Rehoboth Sub: Move Feeder 521 from T1 to T2											
	UDLBLM7M.2	Install Dist Regulators- Fdr Load Relief - Millsboro											
	UDLBLM7M.6	Five Points DE0528: R/C & Install Reclosers											
	UDLBLMG1	Magnolia Area 230/25kV Substation: Build two new 25kV Distribution Lines											
	UDSBLFP1	Five Points- T2 Add New Brkr											
	UDLBLMW2	Midway: Extend New Feeder											
	UDSBLM72A	Clayton Sub Replace T3	31,157	5,501	-82.3%	697,263	557,815	-20.0%	55,876				
	UDSBLM72B	Cedar Neck T1: Upgrade Bus				68,854	36,003	-47.7%					
	UDSBLM73A	Millsboro T2: Upgrade Disconnect Switch				12,305		-100.0%	37,124				
	UDSBLM73B	Midway Substation: Install New Transformer											
	UDSBLM73C	Harbeson Sub: Upgrade T-1							1,680,396				
	UDSBLM76A	Cedar Neck: Install 2nd 69/12kV Transformer[2]					400,644	NA	430,482				
	UDSBLM7D	Future Projects Dist Sub Bay DE											
	UDSBLMG2	Magnolia Area 230/25kV Substation-Build New Substation											
	UDLNLCBC2	Mount Pleasant T2: Extend a New 25 kv Fdr											
	UDLNLM7C	Future Projects Dist Line Christiana											
	UDLNLM7C	Christiana - Feeder Load Relief	244,501	840,003	243.6%	73,683		-100.0%	453,340				
	UDLNLM7C.10	Christiana - Distribution VAR Correction					71,787	NA					
	UDLNLM7C.11	Bear DE0752: Reconductor the Getaway											
	UDLNLM7C.17	Mermaid DE0745: Reconductor Getaway/Add Recloser											
	UDLNLM7C.2	Install Dist Regulators - Fdr Load Relief- Christiana											
	UDLNLM7C.21	Churchman's DE0256: Reconductor Getaway											
	UDSNLM72A	W.Wilmington Sub bus and breaker upgrade				512,451		-100.0%	451,489				
	UDSNLM7D	NC-DE Future projects					329,256	NA					
SUBTOTAL			$987,360	$1,303,775	32.0%	$2,720,320	$2,281,930	-16.1%	$3,637,699	$5,627,493	$3,797,420	$3,967,610	$6,879,880
TOTAL			$ 14,229,348	$ 11,568,213	-18.7%	$ 27,502,487	$ 26,491,891	-3.7%	$ 35,906,023	$ 36,327,961	$ 38,246,192	$ 39,375,438	$ 44,319,157

[1]See response to AG-REL-1(b)2, which states that AG-GEN-1 Attachment D is REP-only expenditures.
[2]Not included in Pro Forma Adjustment 26.
Source: Company's Response to Data Request AG-GEN-1, Attachment D.

Reliability Enhancement Plan Projects with Prior Year Deferrals or Unspent Funds

Witness: Dismukes
Docket No. 13-115
Schedule DED-6
Page 1 of 1

WBS Element	Reliability Enhancement Project Description	Adjustment 26 Amount	Deferred/Unspent Amount
UDLBLM7M	Millsboro District System Planning Recommended Feeder Load Relief	$ 528,992	$ 528,992
UDLBRM4MC	Millsboro District Replace Underground Distribution Cable (URD) Segments	$ 678,281	
UDLBRM4MD	Millsboro District Planned Replacement Underground Distribution Cable (URD) Loops	$ 1,776,908	
UDLBRM4MF	Millsboro District Priority Circuit Improvements	$ 2,501,877	$ 2,501,877
UDLBRM63M	Millsboro District Feeder Reliability Equipment & Design Improvements	$ 4,324,609	
UDLBRM8BA	Millsboro District Greenwood: 4-25kV Conversion	$ 745,726	
UDLBRM8BB	Millsboro District Wyoming - Convert to 25kV Circuit 2233	$ 695,797	
UDLNLM7C	Christiana District, System Planning Recommended Feeder Load Relief	$ 453,341	$ 453,341
UDLNRDA1C	Christiana District, Distribution Automation Equipment Installation	$ 1,508,748	$ 1,508,748
UDLNRM4CC	Christiana District Replace Underground Distribution Cable (URD) Segments	$ 903,214	$ 903,214
UDLNRM4CD	Christiana District Planned Replacement Underground Distribution Cable (URD) Loops	$ 1,617,641	$ 1,617,641
UDLNRM4CF	Christiana District Priority Circuit Improvements	$ 2,538,288	
UDLNRM63C	Christiana District Feeder Reliability Equipment & Design Improvements	$ 6,057,150	
UDSBLM72A	Clayton Substation - Upgrade #3 Transformer	$ 55,876	
UDSBLM73A	Millsboro Substation - Upgrade #2 Transformer Disconnect Switch	$ 37,124	$ 37,124
UDSBLM73C	Harbeson Substation – Upgrade #1 Transformer	$ 1,680,396	
UDSBRD9SF	Millsboro District Millsboro Substation - Replace T1	$ 1,466,841	
UDSBRDA1D	Millsboro District, Substation Distribution Automation Bay DE	$ 17,795	
UDSNLM72A	West Wilmington Substation - Upgrade Distribution Bus & Breakers	$ 451,488	$ 451,488
UDSNRD8MD	Christiana District Substations Upgrades to SCADA/RTU	$ 304,055	$ 304,055
UDSNRD9KA	Milford Crossroads Substation 12kV Switchgear Replacement	$ 1,818,831	
UDSNRD9KB	Bear Substation – 12kV Switchgear Replacement	$ 1,699,117	
UDSNRDA1C	Christiana District Distribution Automation: Christiana Substations	$ 823,379	
UDSNRM61D	Christiana District Substation Reliability Equipment & Design Improvements	$ 547,709	
UOIBRASRD	Millsboro District, Distribution Automation Automatic Sectionalizing and Restoration Equipment Installation	$ 7,843	
UOINRASRD	Christiana District, Distribution Automation Automatic Sectionalizing and Restoration Equipment Installation	$ 223,263	
UORBORBSM	Millsboro District Distribution Automation Communication Work Install Broad Band Wireless Base Station	$ 168,270	$ 168,270
UORBORCPM	Millsboro District Distribution Automation Communication Work Install - Capiactor Controls	$ 19,270	
UORBORSSM	Millsboro District Distribution Automation Communication Work Install Broad Band Wireless Substation Subscriber Radios	$ 145,734	$ 145,734
UORNOBR1C	Christiana District Distribution Automation Communication Work - Collector to Data Network	$ 313,986	
UORNODA1C	Christiana District Distribution Automation Communication Work - Install Radios in Line Equipment	$ 437,553	$ 437,553
UORNORBSC	Christiana District Distribution Automation Communication Work Install Broad Band Wireless Base Station	$ 314,067	$ 314,067
UORNORSSC	Christiana District Distribution Automation Communication Work Install Broad Band Wireless Substation Subscriber Radios	$ 330,325	$ 330,325
	Total	$ 35,193,494	$ 9,702,429

Source: David E. Dismukes, Direct Testimony, Schedules DED-5 and DED-7; Company's Response to Data Request AG-GEN-1, Attachment D.

Forecasted Reliability Closings Compared to Actual Closings Through March 2013

Witness: Dismukes
Docket No. 13-115
Schedule DED-7

WBS Element	Reliability Project Delaware District Location and Description	January	February	March	April	May	June	July	August	September	October	November	December	Total	Actual Closings as of March 2013	Closings Difference from Forecast: All Projects	Closings Difference from Forecast: Projects Less than Forecasted
UDLBLM7M	Millsboro District System Planning Recommended Feeder Load Relief	$ -	$ -	$ 155,806	$ 19,583	$ 137,699	$ 20,083	$ 20,324	$ 20,682	$ 19,572	$ 34,114	$ 26,406	$ 74,723	$ 528,992	$ 38,665	$ (117,141)	$ (117,141)
UDLBRM3M1	Millsboro District Emergency Repair/Replacements Distribution Line Equipment	$ 241,858	$ 183,021	$ 216,271	$ 166,663	$ 143,749	$ 181,291	$ 345,849	$ 282,898	$ 138,631	$ 122,357	$ 233,432	$ 229,005	$ 2,485,025	$ 420,012	$ (221,138)	$ (221,138)
UDLBRM4MA	Millsboro District Reliability/District Office Minor Distribution System Improvements	$ 18,951	$ 29,405	$ 34,125	$ 139,291	$ 21,329	$ 21,440	$ 34,909	$ 111,240	$ 64,969	$ 68,731	$ 48,399	$ 19,808	$ 612,597	$ 111,218	$ 28,737	
UDLBRM4MC	Millsboro District Replace Underground Distribution Cable (URD) Segments	$ 436	$ 789	$ 78,658	$ 107,369	$ 93,155	$ 10,638	$ 10,638	$ 5,625	$ 103,511	$ 83,051	$ 99,547	$ 84,864	$ 678,281	$ 100,662	$ 20,779	
UDLBRM4MD	Millsboro District Planned Replacement Underground Distribution Cable (URD) Loops	$ 66,213	$ 95,272	$ 164,319	$ 201,731	$ 216,982	$ 97,721	$ 181,896	$ 120,902	$ 193,431	$ 153,407	$ 193,435	$ 91,599	$ 1,776,908	$ 551,945	$ 226,141	
UDLBRM4ME	Millsboro District Deteriorated Pole Replacement	$ -	$ -	$ 17,648	$ -	$ -	$ -	$ -	$ -	$ -	$ 17,840	$ -	$ -	$ 35,488	$ -	$ (17,648)	$ (17,648)
UDLBRM4MF	Millsboro District Priority Circuit Improvements	$ 436	$ 417	$ 5,245	$ 227,433	$ 607,301	$ 606,944	$ 614,160	$ 223,331	$ 79,185	$ 126,424	$ 5,334	$ 5,667	$ 2,501,877	$ 607,843	$ 601,745	
UDLBRM4MH	Millsboro District Avian Protection	$ -	$ -	$ -	$ -	$ 9,959	$ 9,911	$ 10,152	$ -	$ -	$ -	$ -	$ -	$ 30,022	$ -	$ -	
UDLBRM4MJ	Millsboro District Planned Replacement of Distribution Reclosers	$ 51,377	$ 57,991	$ 67,606	$ 66,008	$ 8,074	$ 8,831	$ 18,423	$ 18,748	$ -	$ 59,582	$ 20,331	$ -	$ 376,971	$ 15,411	$ (161,563)	$ (161,563)
UDLBRM4MM	Millsboro District Customer Reliability Improvements	$ -	$ -	$ 18,313	$ 7,753	$ -	$ 23,653	$ 5,122	$ -	$ 11,888	$ 70,443	$ 59,594	$ 8,450	$ 205,216	$ 57,807	$ 39,494	
UDLBRM4MQ	Millsboro District Distribution Upgrades to Devices Experiencing Multi Operations	$ -	$ -	$ 54,247	$ 40,871	$ 35,800	$ 80,286	$ 62,930	$ 46,130	$ 58,928	$ 72,942	$ -	$ -	$ 452,134	$ -	$ (54,247)	$ (54,247)
UDLBRM4RC	Bishop Substation - Lines Upgrade - DE	$ 76,033	$ 66,123	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 142,156	$ 228,840	$ 86,684	
UDLBRM5ND	Millsboro District Line Upgrades for NERC Compliance	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 95,546	$ 60,725	$ 79,039	$ -	$ -	$ 235,310	$ -	$ -	
UDLBRM63M	Millsboro District Feeder Reliability Equipment & Design Improvements	$ 434,142	$ 549,944	$ 503,725	$ 305,187	$ 414,470	$ 28,059	$ 171,822	$ 580,600	$ 326,832	$ 357,557	$ 614,453	$ 37,818	$ 4,324,609	$ 997,360	$ (490,451)	$ (490,451)
UDLBRM8BA	Millsboro District Greenwood: 4-25kV Conversion	$ 249,192	$ 284,153	$ 107,794	$ 104,587	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 745,726	$ 555,788	$ (85,351)	$ (85,351)
UDLBRM8BB	Millsboro District Wyoming - Convert to 25kV Circuit 2233	$ 236,412	$ 259,300	$ 95,817	$ 92,967	$ -	$ 11,301	$ -	$ -	$ -	$ -	$ -	$ -	$ 695,797	$ 194,657	$ (396,872)	$ (396,872)
UDLNLM7C	Christiana District, System Planning Recommended Feeder Load Relief	$ 21,677	$ 21,196	$ 105,070	$ 42,819	$ 44,636	$ 26,219	$ 23,129	$ 23,517	$ 37,952	$ 50,069	$ 34,733	$ 22,324	$ 453,341	$ -	$ (147,943)	$ (147,943)
UDLNRDA1C	Christiana District, Distribution Automation Equipment Installation	$ 228,324	$ 223,263	$ 218,600	$ 190,996	$ 199,099	$ -	$ -	$ -	$ -	$ 220,487	$ 227,979	$ -	$ 1,508,748	$ 49,630	$ (620,557)	$ (620,557)
UDLNRM3C1	Christiana District Emergency Repair/Replacements Distribution Line Equipment	$ 749,657	$ 800,871	$ 847,422	$ 809,080	$ 957,562	$ 1,009,547	$ 1,024,651	$ 1,069,147	$ 847,802	$ 818,066	$ 1,001,544	$ 860,766	$ 10,796,115	$ 3,847,026	$ 1,449,076	
UDLNRM4CA	Millsboro District Reliability/District Office Minor Distribution System Improvements	$ 26,135	$ 25,555	$ 29,397	$ 29,067	$ 30,301	$ 28,865	$ 29,578	$ 49,099	$ 155,917	$ 164,952	$ 170,727	$ 160,097	$ 899,690	$ 962,534	$ 881,447	
UDLNRM4CC	Christiana District Replace Underground Distribution Cable (URD) Segments	$ 32,075	$ 35,766	$ 55,255	$ 60,789	$ 69,479	$ 65,868	$ 67,822	$ 120,402	$ 124,756	$ 125,203	$ 82,599	$ 63,200	$ 903,214	$ 185,577	$ 62,481	
UDLNRM4CD	Christiana District Planned Replacement Underground Distribution Cable (URD) Loops	$ 110,422	$ 107,974	$ 111,858	$ 110,729	$ 115,427	$ 111,674	$ 123,460	$ 165,934	$ 157,967	$ 188,535	$ 147,514	$ 166,147	$ 1,617,641	$ 578,303	$ 248,049	
UDLNRM4CE	Christiana District Deteriorated Pole Replacement	$ -	$ 26,161	$ 25,565	$ 25,393	$ 26,471	$ 35,095	$ 35,958	$ 36,561	$ 34,826	$ 35,953	$ 37,727	$ 10,861	$ 330,571	$ 229,314	$ 177,588	
UDLNRM4CF	Christiana District Priority Circuit Improvements	$ 173,142	$ 171,060	$ 168,022	$ 311,992	$ 324,370	$ 304,891	$ 315,736	$ 394,521	$ 349,827	$ 24,727	$ -	$ -	$ 2,538,288	$ 204,098	$ (308,126)	$ (308,126)
UDLNRM4CH	Christiana District Avian Protection	$ -	$ -	$ -	$ -	$ -	$ 11,080	$ 11,308	$ 12,278	$ 10,763	$ 1,570	$ -	$ -	$ 46,999	$ -	$ -	
UDLNRM4CJ	Christiana District Planned Replacement of Distribution Reclosers	$ -	$ -	$ 59,189	$ 59,288	$ 62,544	$ 58,715	$ 61,052	$ 62,811	$ 59,037	$ 62,289	$ 20,937	$ -	$ 505,862	$ 110,675	$ 51,486	
UDLNRM4CM	Christiana District Customer Reliability Improvements	$ -	$ -	$ 54,200	$ 53,414	$ 55,680	$ 53,247	$ 54,352	$ 55,263	$ 53,533	$ 53,741	$ -	$ -	$ 433,430	$ 196,682	$ 142,482	
UDLNRM4CQ	Christiana District Distribution Upgrades to Devices Experiencing Multi Operations	$ -	$ -	$ 61,738	$ 61,007	$ 63,595	$ 62,057	$ 63,524	$ 64,589	$ 61,577	$ 64,488	$ -	$ -	$ 502,575	$ -	$ (61,738)	$ (61,738)
UDLNRM4CR	Wilmington Network Upgrade	$ 35,921	$ 35,125	$ 33,607	$ 34,095	$ 35,541	$ 27,388	$ 28,911	$ 29,396	$ 27,238	$ 28,907	$ 104,612	$ 27,905	$ 448,646	$ (8,054)	$ (112,707)	$ (112,707)
UDLNRM5ND	Christiana District Line Upgrades for NERC Compliance	$ -	$ -	$ -	$ 121,558	$ 37,533	$ 34,707	$ 32,712	$ -	$ -	$ -	$ -	$ -	$ 226,510	$ -	$ -	
UDLNRM5SC	Christiana District Christiana Substation Feeder relocation	$ 381,114	$ 397,112	$ 377,861	$ 346,257	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 1,502,344	$ 1,633,700	$ 477,613	

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UDLNRM5SD	Christiana District Reconductor Feeder DE0217	$ 145,801	$ 142,569	$ 141,615	$ 138,387	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 568,372	$ 114,619	$ (315,366)	$ (315,366)
UDLNRM5SE	Christiana District Cable Replacement for New Substation Switch Gears	$ -	$ 80,399	$ 79,786	$ 78,041	$ -	$ -	$ -	$ -	$ -	$ 79,399	$ 82,097	$ 80,617	$ 480,339	$ 236,958	$ 76,773	
UDLNRM63C	Christiana District Feeder Reliability Equipment & Design Improvements	$ 660,156	$ 590,285	$ 666,151	$ 277,397	$ 347,922	$ 282,561	$ 259,199	$ 704,384	$ 304,349	$ 463,103	$ 861,398	$ 640,247	$ 6,057,150	$ 233,765	$ (1,682,827)	$ (1,682,827)
UDLNRM8SE	Christiana District.-Rebuild Overhead Rear Lot Distribution System	$ -	$ -	$ -	$ -	$ -	$ 77,973	$ 81,350	$ 82,714	$ 77,479	$ 21,680	$ -	$ -	$ 341,196	$ -	$ -	
UDLNRM8SH	Churchmans Substation - Replace Reclosers	$ 6,451	$ 6,308	$ 2,506	$ 2,449	$ 1,277	$ 1,233	$ -	$ -	$ -	$ -	$ -	$ -	$ 20,224	$ -	$ (15,265)	$ (15,265)
UDLNRM9SB	Christiana District Replace Steel Poles along 4th St. Wilm	$ -	$ 92,437	$ 90,599	$ 89,725	$ 93,532	$ 88,938	$ 91,756	$ -	$ -	$ -	$ -	$ -	$ 546,987	$ 27,361	$ (155,675)	$ (155,675)
UDLNRMT1	Christiana District MILLTOWN RD - MOVE DE0640 FROM T1 TO T3	$ -	$ -	$ 25,065	$ 69,071	$ 91,587	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 185,823	$ -	$ (25,065)	$ (25,065)
UDSBLM72A	Clayton Substation - Upgrade #3 Transformer	$ 55,876	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 55,876	$ 48,280	$ (7,596)	$ (7,596)
UDSBLM73A	Millsboro Substation - Upgrade #2 Transformer Disconnect Switch	$ 1,316	$ -	$ -	$ 35,808	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 37,124	$ 1,727	$ 411	
UDSBLM73C	Harbeson Substation – Upgrade #1 Transformer	$ 353,285	$ 108,580	$ 213,135	$ 611,288	$ 337,063	$ 51,957	$ 5,088	$ -	$ -	$ -	$ -	$ -	$ 1,680,396	$ 262,180	$ (412,820)	$ (412,820)
UDSBRD71D	Millsboro District Emergency Repair/Replacements Distribution Sub Equipmen	$ -	$ -	$ -	$ -	$ -	$ 936	$ 66,795	$ 10,501	$ -	$ -	$ 996	$ 57,632	$ 136,860	$ -	$ -	
UDSBRD8AD	Millsboro District Substation Planned Improvements	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 468	$ -	$ -	$ -	$ 35,249	$ -	$ -	
UDSBRD8BD	Millsboro District Misc Relay Blanket	$ -	$ -	$ -	$ -	$ 4,548	$ -	$ 30,233	$ -	$ -	$ -	$ -	$ -	$ 47,407	$ 17,072	$ 10,862	
UDSBRD8DD	Millsboro District Laurel substation - DPU Replacement	$ -	$ 1,350	$ 1,264	$ 663	$ 5,215	$ 8,759	$ 4,862	$ 4,724	$ 19,445	$ 52,829	$ 19,933	$ 41,262	$ 160,406	$ 637	$ (1,977)	$ (1,977)
UDSBRD8ED	Millsboro District Distribution Substation Battery Replacements	$ -	$ 3,271	$ 3,161	$ 587	$ 592	$ 7,759	$ 38,647	$ 12,760	$ -	$ -	$ -	$ -	$ 66,777	$ 53,779	$ 47,347	
UDSBRD8FD	Millsboro District Distribution Substation Bushing Replacements	$ 658	$ -	$ 11,644	$ 21,389	$ -	$ -	$ 664	$ 24,996	$ -	$ 42,456	$ -	$ 638	$ 102,445	$ 9,320	$ (2,982)	$ (2,982)
UDSBRD8G	Millsboro District - PHI Spare Transformers	$ 341,061	$ 62,988	$ 65,693	$ 12,196	$ 351,530	$ 139,840	$ 5,862	$ 5,356	$ 165,367	$ 5,590	$ 2,452	$ 2,362	$ 1,160,295	$ 293,557	$ (176,184)	$ (176,184)
UDSBRD8G2	Millsboro District- Purchase Mobile Transformer	$ 31,839	$ 286,845	$ 33,786	$ 297,026	$ 2,798	$ 264,592	$ 951	$ 971	$ -	$ -	$ -	$ -	$ 918,806	$ -	$ (352,470)	$ (352,470)
UDSBRD8G3	Millsboro District purchase 138/25kV Mobile Unit	$ 4,704	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 4,704	$ -	$ (4,704)	$ (4,704)
UDSBRD8G4	Millsboro District 138x69kV / 25kV 30MVA Mobile Unit	$ 28,165	$ 311,077	$ 31,633	$ 321,016	$ 1,803	$ 271,663	$ 332	$ 340	$ -	$ -	$ -	$ -	$ 966,027	$ -	$ (370,875)	$ (370,875)
UDSBRD8ID	Millsboro District Distribution Substation Control House Roofs Replacements)	$ 658	$ -	$ -	$ 67,103	$ 67,621	$ 67,337	$ 67,278	$ 88,718	$ 67,015	$ -	$ -	$ 638	$ 406,368	$ -	$ (658)	$ (658)
UDSBRD8MD	Millsboro District Substations Upgrades to SCADA/RTU	$ -	$ -	$ -	$ -	$ 1,336	$ -	$ -	$ 23,547	$ 12,347	$ -	$ -	$ -	$ 42,073	$ -	$ -	
UDSBRD8PD	Millsboro District Reg Distribution Substation Misc Equip Retirement	$ -	$ -	$ -	$ -	$ -	$ -	$ 5,260	$ -	$ -	$ -	$ 2,018	$ 2,825	$ 10,532	$ -	$ -	
UDSBRD8VD	Millsboro District, Installation Cyber Security Improvements	$ -	$ -	$ -	$ -	$ -	$ 5,687	$ 7,317	$ -	$ 151,435	$ 558	$ 570	$ -	$ 165,567	$ 158	$ 158	
UDSBRD9DD	Millsboro District Distribution Substation Breaker Replacements	$ 19,826	$ 11,958	$ 198,689	$ 84,416	$ 30,083	$ 2,960	$ 20,015	$ 167,276	$ 24,618	$ 14,801	$ 6,450	$ 2,993	$ 584,085	$ 52,316	$ (178,157)	$ (178,157)
UDSBRD9SF	Millsboro District Millsboro Substation - Replace T1	$ 7,410	$ 1,358	$ 5,426	$ 387,940	$ 14,526	$ 90,663	$ 62,153	$ 408,724	$ 167,240	$ 316,759	$ 2,729	$ 1,913	$ 1,466,841	$ 139,428	$ 125,234	
UDSBRDA1D	Millsboro District, Substation Distribution Automation Bay DE	$ 2,083	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 1,894	$ 8,552	$ 4,078	$ 3,188	$ 17,795	$ (7,935)	$ (10,018)	$ (10,018)
UDSNLM72A	West Wilmington Substation - Upgrade Distribution Bus & Breakers	$ 40,152	$ 96,769	$ 126,158	$ 119,852	$ 68,557	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 451,488	$ 330,736	$ 67,657	
UDSNRD71D	Christiana District Emergency Repair/Replacements Distribution Sub Equipmen	$ 37,145	$ -	$ -	$ -	$ -	$ 50,553	$ 53,020	$ 21,997	$ 6,980	$ 10,722	$ 41,747	$ 13,492	$ 235,656	$ 57,118	$ 19,973	
UDSNRD8AD	Christiana District Substation Planned Improvements	$ -	$ -	$ -	$ -	$ -	$ 25,752	$ 22,929	$ -	$ -	$ 3,940	$ 38,307	$ 7,118	$ 98,046	$ 556	$ 556	
UDSNRD8BD	Christiana District Misc Relay Blanket	$ -	$ -	$ -	$ 4,358	$ 6,509	$ 9,985	$ -	$ 18,940	$ 1,613	$ 2,577	$ 17,434	$ -	$ 61,416	$ -	$ -	
UDSNRD8ED	Christiana District Distribution Substation Battery Replacements	$ -	$ -	$ -	$ -	$ 10,380	$ 3,889	$ 53,613	$ 24,300	$ 10,889	$ -	$ -	$ -	$ 103,071	$ -	$ -	

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UDSNRD8FD	Christiana District Distribution Substation Bushing Replacements	$ -	$ -	$ 6,862	$ 923	$ -	$ 42,822	$ -	$ -	$ 21,361	$ 13,008	$ 33,631	$ 3,460	$ 122,067	$ 7,003	$ 141	
UDSNRD8G	Christiana District Spare Distribution Transformer	$ 3,511	$ 232,141	$ 120,586	$ 6,886	$ 24,310	$ 262,154	$ 4,777	$ 14,542	$ 3,157	$ 280,021	$ 170,854	$ 2,219	$ 1,125,158	$ 131,733	$ (224,505)	$ (224,505)
UDSNRD8G1	Christiana District- Purchase 138/69 -12 kV Mobile XFMRs	$ -	$ 680,928	$ 1,290,854	$ -	$ 14,708	$ 4,739	$ 1,301,287	$ 13,013	$ -	$ 3,288	$ 481,484	$ -	$ 3,790,301	$ 13,225	$ (1,958,557)	$ (1,958,557)
UDSNRD8GD	Christiana Substation, Upgrade #2 Transformer	$ 124,303	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 124,303	$ 185,172	$ 60,869	
UDSNRD8MD	Christiana District Substations Upgrades to SCADA/RTU	$ -	$ 69,029	$ 14,771	$ 10,439	$ 34,107	$ 40,797	$ 5,088	$ 32,856	$ 70,641	$ 20,371	$ 5,956	$ -	$ 304,055	$ 211	$ (83,589)	$ (83,589)
UDSNRD8PD	Christiana District Reg Distribution Substation Misc Equip Retirement	$ -	$ -	$ -	$ -	$ 1,424	$ 3,682	$ 6,152	$ -	$ 879	$ 4,589	$ 5,811	$ 1,977	$ 24,514	$ -	$ -	
UDSNRD8SA	Churchmans Substation RECLOSER REMOVAL	$ -	$ -	$ -	$ -	$ 2,324	$ -	$ 4,415	$ 13,915	$ 24,250	$ 1,315	$ -	$ -	$ 46,219	$ -	$ -	
UDSNRD8SE	Christiana District Silverbrook substation - Replace Failed #3 Transformer	$ -	$ -	$ -	$ -	$ -	$ -	$ 105,123	$ 107,371	$ 52,355	$ -	$ -	$ -	$ 264,849	$ 333,712	$ 333,712	
UDSNRD8SI	Chapel Street Substation - Resupply Station Service	$ -	$ -	$ -	$ -	$ 15,088	$ -	$ -	$ 45,354	$ -	$ -	$ 17,959	$ 9,676	$ 88,077	$ -	$ -	
UDSNRD8VD	Christiana District Installation Cyber Security Improvements	$ -	$ -	$ -	$ -	$ 227,233	$ 164,692	$ -	$ -	$ 15,049	$ 212,033	$ 165,413	$ -	$ 784,420	$ 9,767	$ 9,767	
UDSNRD9DD	Christiana District Distribution Substation Breaker Replacements	$ 1,624	$ 26,749	$ 124,694	$ 110,816	$ 225,304	$ 137,794	$ 95,323	$ 161,386	$ 154,015	$ 173,684	$ 143,124	$ 45,486	$ 1,399,999	$ 172,832	$ 19,765	
UDSNRD9FD	Christiana District REPLACE/UPGRADE Potential Transformers	$ -	$ -	$ 16,797	$ 7,968	$ 10,777	$ 1,660	$ -	$ -	$ 24,994	$ 6,985	$ -	$ -	$ 69,201	$ 28,387	$ 11,590	
UDSNRD9HD	Christiana District Replace 34.5kV Capacitor Banks		$ 411	$ 3,111	$ 13,141	$ 11,927	$ 9,166	$ 6,610	$ 10,512	$ 27,589	$ 99,943	$ 70,631	$ 34,011	$ 287,052	$ 17,243	$ 13,721	
UDSNRD9KA	Milford Crossroads Substation 12kV Switchgear Replacement	$ 6,789	$ 6,749	$ 22,937	$ 162,967	$ 155,582	$ 191,893	$ 235,821	$ 162,227	$ 208,734	$ 265,634	$ 242,390	$ 157,088	$ 1,818,831	$ 19,410	$ (17,065)	$ (17,065)
UDSNRD9KB	Bear Substation – 12kV Switchgear Replacement	$ 6,852	$ 6,811	$ 12,784	$ 13,400	$ 189,319	$ 227,137	$ 276,199	$ 175,176	$ 335,020	$ 271,961	$ 147,984	$ 36,474	$ 1,699,117	$ 17,656	$ (8,791)	$ (8,791)
UDSNRD9SE	Edge Moor Substation- Upgrade 12kV Main Breakers	$ -	$ 23,651	$ 61,664	$ 62,456	$ 31,165	$ 28,882	$ -	$ -	$ -	$ -	$ -	$ -	$ 207,818	$ 369	$ (84,946)	$ (84,946)
UDSNRD9SH	Brookside Substation - Upgrade #2 Transformer	$ 111,711	$ 703,769	$ 669,429	$ 396,143	$ 185,671	$ 10,090	$ 3,322	$ -	$ -	$ -	$ -	$ -	$ 2,080,135	$ 1,337,932	$ (146,977)	$ (146,977)
UDSNRD9SJ	Christiana District MILFORD CROSSROADS T2 UPGRADE	$ 186,139	$ 71,728	$ 112,472	$ 14,150	$ 5,283	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 389,772	$ 329,133	$ (41,206)	$ (41,206)
UDSNRD9SK	West Substation - Replace T-2 69/34 kV 18 MVA Transformer	$ -	$ -	$ 3,223	$ 275,760	$ 4,641	$ 15,782	$ 271,006	$ 6,545	$ 9,996	$ 277,424	$ 128,132	$ 86,557	$ 1,079,066	$ 116,217	$ 112,994	
UDSNRD9ZD	Christiana District Replace Deteriorated Switches	$ -	$ -	$ -	$ 17,954	$ 1,259	$ -	$ 17,480	$ 14,246	$ 16,580	$ 1,315	$ -	$ 3,954	$ 72,788	$ -	$ -	
UDSNRDA1C	Christiana District Distribution Automation: Christiana Substations	$ 27,699	$ 27,535	$ 106,094	$ 110,468	$ 39,812	$ 53,804	$ 65,933	$ 99,748	$ 113,296	$ 131,407	$ 42,701	$ 4,882	$ 823,379	$ 749,202	$ 587,874	
UDSNRM61D	Christiana District Substation Reliability Equipment & Design Improvements	$ 240,916	$ 187,299	$ -	$ -	$ -	$ -	$ 40,998	$ 45,826	$ 32,670	$ -	$ -	$ -	$ 547,709	$ 750,309	$ 322,094	
UDSNRMT2	Milltown Substation Move Feeder to 640	$ -	$ -	$ -	$ -	$ -	$ -	$ 5,290	$ 15,423	$ 41,496	$ 24,421	$ 4,555	$ -	$ 91,185	$ -	$ -	
UOIBRASRD	Millsboro District, Distribution Automation Automatic Sectionalizing and Restoration	$ 4,349	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 7,843	$ -	$ (4,349)	$ (4,349)
UOINRASRD	Christiana District, Distribution Automation Automatic Sectionalizing and Restoration	$ 55,843	$ 13,892	$ 11,086	$ 17,465	$ 5,227	$ 4,933	$ 45,174	$ 20,352	$ 12,178	$ 12,717	$ 17,357	$ 7,039	$ 223,263	$ -	$ (80,821)	$ (80,821)
UORBORBSM	Millsboro District Distribution Automation Communication Work Install Broad Band Wireless	$ 1,112	$ 1,106	$ 1,513	$ 3,725	$ 19,023	$ 23,221	$ 31,230	$ 30,577	$ 21,821	$ 19,396	$ 9,977	$ 5,569	$ 168,270	$ -	$ (3,731)	$ (3,731)
UORBORCPM	Millsboro District Distribution Automation Communication Work Install - Capiactor Controls	$ -	$ -	$ -	$ -	$ -	$ -	$ 19,270	$ -	$ -	$ -	$ -	$ -	$ 19,270	$ -	$ -	
UORBORSSM	Millsboro District Distribution Automation Communication Work Install Broad Band Wireless	$ 1,112	$ 1,106	$ 1,513	$ 3,725	$ 12,000	$ 17,821	$ 19,129	$ 32,597	$ 26,669	$ 11,719	$ 12,863	$ 5,480	$ 145,734	$ -	$ (3,731)	$ (3,731)
UORN0BR1C	Christiana District Distribution Automation Communication Work - Collector to Data Network	$ 6,319	$ 6,742	$ 6,745	$ 6,448	$ 5,941	$ 6,555	$ 37,683	$ 58,248	$ 79,257	$ 65,383	$ 23,611	$ 11,054	$ 313,986	$ -	$ (19,806)	$ (19,806)
UORN0DA1C	Christiana District Distribution Automation Communication Work - Install Radios in Line	$ 10,600	$ 78,092	$ 78,274	$ 79,098	$ 79,709	$ 39,068	$ 1,871	$ 4,295	$ 3,996	$ 30,864	$ 31,686	$ -	$ 437,553	$ -	$ (166,966)	$ (166,966)
UORNORBSC	Christiana District Distribution Automation Communication Work Install Broad Band Wireless	$ 463	$ 737	$ 5,944	$ 37,858	$ 49,756	$ 72,930	$ 64,431	$ 25,735	$ 30,597	$ 10,626	$ 9,343	$ 5,647	$ 314,067	$ -	$ (7,144)	$ (7,144)
UORNORSSC	Christiana District Distribution Automation Communication Work Install Broad Band Wireless	$ 463	$ 737	$ 5,944	$ 37,212	$ 49,756	$ 73,770	$ 67,996	$ 27,856	$ 35,842	$ 16,220	$ 10,169	$ 4,360	$ 330,325	$ -	$ (7,144)	$ (7,144)
	Total	$ 5,659,907	$ 7,305,904	$ 8,047,176	$ 7,743,661	$ 6,551,793	$ 5,817,783	$ 6,960,191	$ 6,300,517	$ 5,372,186	$ 6,060,093	$ 5,985,141	$ 3,152,459	$ 74,956,809	$ 17,960,841	$ (3,052,145)	$ (9,367,444)

Source: Jay C. Ziminsky, Direct Testimony, Adjustment 26 Support; Company's Response to Data Request AG-GEN-1, Attachment A.

Adjustment 26 Reliability and Non-Reliability Enhancement Projects

WBS Element	Project Description	REP Projects		Non-REP Projects	
		Detailed Description	Amount	Detailed Description	Amount
UDLBLM7M	Millsboro District System Planning Recommended Feeder Load Relief	No Description Provided	$ 528,992		$ -
UDLBRM3M1	Millsboro District Emergency Repair/Replacements Distribution Line Equipment		$ -	Funds necessary for the emergency restoration of customers.	$ 2,485,025
UDLBRM4MA	Millsboro District Reliability/District Office Minor Distribution System Improvements		$ -	Capital work necessary to maintain electric service in the Millsboro District. Improvement of equipment replacement due to load and/or rearrangement requiring design	$ 612,597
UDLBRM4MC	Millsboro District Replace Underground Distribution Cable (URD) Segments	Capital work necessary to replace underground cables due to failures.	$ 678,281		$ -
UDLBRM4MD	Millsboro District Planned Replacement Underground Distribution Cable (URD) Loops	Capital work necessary to maintain and replace the underground cables in subdivisions due to multiple failures.	$ 1,776,908		$ -
UDLBRM4ME	Millsboro District Deteriorated Pole Replacement		$ -	No Description Provided	$ 35,488
UDLBRM4MF	Millsboro District Priority Circuit Improvements	Install, remove, replace reclosers, switches, guards, and other equipment deemed necessary on the worst performing feeder circuits in Millsboro District, to improve and maintain continued safe and reliable operation.	$ 2,501,877		$ -
UDLBRM4MH	Millsboro District Avian Protection		$ -	No Description Provided	$ 30,022
UDLBRM4MJ	Millsboro District Planned Replacement of Distribution Reclosers		$ -	Capital work necessary to replace reclosers to provide for a properly operating distribution system.	$ 376,971
UDLBRM4MM	Millsboro District Customer Reliability Improvements		$ -	Capital work needed to complete projects aimed at specific customer reliability focused intiatives	$ 205,216
UDLBRM4MQ	Millsboro District Distribution Upgrades to Devices Experiencing Multi		$ -	No Description Provided	$ 452,134
UDLBRM4RC	Bishop Substation - Lines Upgrade - DE		$ -	Upgrade 4/0 CU from Bishop to Selbyville with 954-AAC for new Bishop circuit. Funds needed for 2012 carry over into 2013	$ 142,156
UDLBRM5ND	Millsboro District Line Upgrades for NERC Compliance		$ -	No Description Provided	$ 235,310
UDLBRM63M	Millsboro District Feeder Reliability Equipment & Design Improvements	Capital work necessary to improve Reliability in Millsboro District	$ 4,324,609		$ -
UDLBRM8BA	Millsboro District Greenwood: 4-25kV Conversion	Convert Greenwood feeder DE0558 from 4kV to 25kV, and replace/ upgrade all the deteriorated hardware.	$ 745,726		$ -

Adjustment 26 Reliability and Non-Reliability Enhancement Projects

WBS Element	Project Description	REP Projects		Non-REP Projects	
		Detailed Description	Amount	Detailed Description	Amount
UDLBRM8BB	Millsboro District Wyoming - Convert to 25kV Circuit 2233	Convert Wyoming feeder DE0513 from 4kV to 25KV, and replace/ upgrade all the deteriorated hardware.	$ 695,797		$ -
UDLNLM7C	Christiana District, System Planning Recommended Feeder Load Relief	Install 1200 & 2400kvar cap banks at various locations as directed by System Planning	$ 453,341		$ -
UDLNRDA1C	Christiana District, Distribution Automation Equipment Installation	Distribution automation work in the Christiana District	$ 1,508,748		$ -
UDLNRM3C1	Christiana District Emergency Repair/Replacements Distribution Line Equipment		$ -	Capital work needed to maintain or restore electric service	$10,796,115
UDLNRM4CA	Millsboro District Reliability/District Office Minor Distribution System		$ -	Capital work necessary to maintain electric service.	$ 899,690
UDLNRM4CC	Christiana District Replace Underground Distribution Cable (URD) Segments	Capital work necessary to replace underground cables due to failures.	$ 903,214		$ -
UDLNRM4CD	Christiana District Planned Replacement Underground Distribution Cable (URD) Loops	Capital work necessary to maintain and replace the underground cables in subdivisions due to multiple failures.	$ 1,617,641		$ -
UDLNRM4CE	Christiana District Deteriorated Pole Replacement		$ -	Replace and/or reinforce failing poles in the Christiana District	$ 330,571
UDLNRM4CF	Christiana District Priority Circuit Improvements	Install, remove, replace reclosers, switches, guards, and other equipment deemed necessary on the worst performing feeder circuits in Centreville District, to improve and maintain continued safe and reliable operation.	$ 2,538,288		$ -
UDLNRM4CH	Christiana District Avian Protection		$ -	No Description Provided	$ 46,999
UDLNRM4CJ	Christiana District Planned Replacement of Distribution Reclosers		$ -	Replace line reclosers periodically to provide for a properly operating distribution system.	$ 505,862
UDLNRM4CM	Christiana District Customer Reliability Improvements		$ -	Address customer concerns about recent reliability issues. Install fuses, reclosers, trim trees, reconductor, etc.	$ 433,430
UDLNRM4CQ	Christiana District Distribution Upgrades to Devices Experiencing Multi Operations		$ -	No Description Provided	$ 502,575
UDLNRM4CR	Wilmington Network Upgrade		$ -	Upgrade the aerial sections of the Wilmington Network by replacing poles, wires and adding distribution transformers as needed.	$ 448,646

Adjustment 26 Reliability and Non-Reliability Enhancement Projects

WBS Element	Project Description	REP Projects		Non-REP Projects	
		Detailed Description	Amount	Detailed Description	Amount
UDLNRM5ND	Christiana District Line Upgrades for NERC Compliance		$ -	No Description Provided	$ 226,510
UDLNRM5SC	Christiana District Christiana Substation Feeder relocation		$ -	Install new conduit and manhole system to relocate 27 distribution feeders serving the City of Wilmington	$ 1,502,344
UDLNRM5SD	Christiana District Reconductor Feeder DE0217		$ -	Reconductor circuit DE0217, which serves as the back-up to Riverside Hospital. Circuit DE0217 has experienced numerous failures in recent months and has had to be taken out of service until the primary distribution cable can be upgraded	$ 568,372
UDLNRM5SE	Christiana District Cable Replacement for New Substation Switch Gears		$ -	Replace Cable from breakers to first manhole for all feeders on new substation switchgears.	$ 480,339
UDLNRM63C	Christiana District Feeder Reliability Equipment & Design Improvements	Capital work necessary to improve Reliability in Centreville District	$ 6,057,150		$ -
UDLNRM8SE	Christiana District.-Rebuild Overhead Rear Lot Distribution System		$ -	No Description Provided	$ 341,196
UDLNRM8SH	Churchmans Substation - Replace Reclosers		$ -	No Description Provided	$ 20,224
UDLNRM9SB	Christiana District Replace Steel Poles along 4th St. Wilm		$ -	Replace deteriorating steel poles along 4th Street in Wilmington.	$ 546,987
UDLNRMT1	Christiana District MILLTOWN RD - MOVE DE0640 FROM T1 TO T3		$ -	No Description Provided	$ 185,823
UDSBLM72A	Clayton Substation - Upgrade #3 Transformer	Replace T3 transformer at Clayton Substation with a 3.2 MVA, three-phase transformer. Add voltage regulators and low side recloser. Plan to build new foundation with oil containment near the existing transformer along with foundations for new recloser and regulators. New transformer will still be protected by high-side fuses. Plan to build all ahead of time then do a short overnight outage to transfer load to the new transformer.	$ 55,876		$ -
UDSBLM73A	Millsboro Substation - Upgrade #2 Transformer Disconnect Switch	Replace the T2 low side disconnect switch and 500 MCM bus. Rating of T2 low side terminal to be 34 MVA (787 A) Normal Rating.	$ 37,124		$ -

Adjustment 26 Reliability and Non-Reliability Enhancement Projects

WBS Element	Project Description	REP Projects		Non-REP Projects	
		Detailed Description	Amount	Detailed Description	Amount
UDSBLM73C	Harbeson Substation – Upgrade #1 Transformer	Replace Harbeson T1 with new 69-25kV 37MVA Transformer New transformer will be located on new foundation near 25kV structure. 69kV terminal will be designed to connect to new T1 high side switch with MOD. Installation will include removing 25kV regulators, installing new 25kV low side circuit breaker for and new tie circuit breaker for 25kV bus.T1, disconnect switches for T1 low side breaker, low side disconnect for T1, Installation will include new SEL 451s for breaker control for CBs 3140 and 3190 and an SEL 487E and SEL 451 for transformer differential protection.	$ 1,680,396		$ -
UDSBRD71D	Millsboro District Emergency Repair/Replacements Distribution Sub Equipmen		$ -	No Description Provided	$ 136,860
UDSBRD8AD	Millsboro District Substation Planned Improvements		$ -	No Description Provided	$ 35,249
UDSBRD8BD	Millsboro District Misc Relay Blanket		$ -	This project is a blanket that does not have a defined scope yet. This blanket is intended for very simple misc. relay upgrades that may need to be completed each year.	$ 47,407
UDSBRD8DD	Millsboro District Laurel substation - DPU Replacement		$ -	Replace the existing DPU relays with SEL451/SEL551 feeder protection/control packages at Laurel substation. Replace DPU relay on feeder 506 and remove old DPU equipment. Replace CB 1. An Orion-LX and a GPS clock will be added to replace the existing SEL-2030 which are included in this estimate.	$ 160,406
UDSBRD8ED	Millsboro District Distribution Substation Battery Replacements		$ -	Replace Bay Distribution Substation Batteries and Chargers in two Delaware locations which have deteriorated, tested poorly or have reached end of life.	$ 66,777
UDSBRD8FD	Millsboro District Distribution Substation Bushing Replacements		$ -	2013-2017: Replace bushing sets on 3 distribution transformers in 2013 and then 2 per year through 2017 within the Bay Region in Delaware that have deteriorated or tested poorly.	$ 102,445
UDSBRD8G	Millsboro District - PHI Spare Transformers		$ -	Purchase spare distribution transformers for Bay Region. Included in estimate are following: 1. Purchase of 138/12kV, 37MVA transformer, ISD June 2013, including foundation construction, offloading costs, testing, assembly, engineering and consulting costs, and total cost of transformer 2. Purchase of 69/12kV, 37MVA transformer, ISD June 2013, including foundation construction, offloading costs, testing, assembly, engineering and consulting costs, and total cost of transformer 3. Purchase of 69/25kV, 37MVA transformer, ISD June 2014, including foundation construction, offloading costs, testing, assembly, engineering and consulting costs, and total cost of transformer	$ 1,160,295

Adjustment 26 Reliability and Non-Reliability Enhancement Projects

WBS Element	Project Description	REP Projects		Non-REP Projects	
		Detailed Description	Amount	Detailed Description	Amount
UDSBRD8G2	Millsboro District- Purchase Mobile Transformer		$ -	No Description Provided	$ 918,806
UDSBRD8G3	Millsboro District purchase 138/25kV Mobile Unit		$ -	No Description Provided	$ 4,704
UDSBRD8G4	Millsboro District 138x69kV / 25kV 30MVA Mobile Unit		$ -	No Description Provided	$ 966,027
UDSBRD8ID	Substation Control House Roofs Replacements)		$ -	No Description Provided	$ 406,368
UDSBRD8MD	Millsboro District Substations Upgrades to SCADA/RTU		$ -	No Description Provided	$ 42,073
UDSBRD8PD	Millsboro District Reg Distribution Substation Misc Equip Retirement		$ -	No Description Provided	$ 10,532
UDSBRD8VD	Millsboro District, Installation Cyber Security Improvements		$ -	Since no scope was available from the Security department and no defintive plans for DA in Delaware, this estimate assumes one installation per year of a physical security system consisting of key card locks on the substation control house doors, a key card lock and motorized sliding gate on one fence gate, and a Future Sentry perimeter security system with all associated sensors and solar power	$ 165,567
UDSBRD9DD	Millsboro District Distribution Substation Breaker Replacements		$ -	2013-2017 - Replace ten distribution oil breakers per year through 2015, then replace twenty per year for years 2016 and 2017. Estimates are split evenly between Maryland and Delaware because deteriorated breakers cannot be determined until testing. For budgeting, assumed all breakers are 27kV, 1200A.	$ 584,085
UDSBRD9SF	Millsboro District Millsboro Substation - Replace T1	1. Remove the existing 15 MVA transformer T2 2. Replace it with 69/25KV 40MVA Transformer with LTC 3. Remove the existing FL & BU relays and replace it with new SEL 487E as FL and SEL 551 as BU relays 4. Add Orion-LX, Ethernet switch and GPS clock 5. New foundation and new Oil containment required 6. Assembly and testing to be done by Transformer manufacturer 7. Assume first 30% progress payment of $360k is made in 2012.	$ 1,466,841		$ -
UDSBRDA1D	Millsboro District, Substation Distribution Automation Bay DE	Substation Distribution Automation Projects in Bay Region - Delaware	$ 17,795		$ -
UDSNLM72A	West Wilmington Substation - Upgrade Distribution Bus & Breakers	Install two(2)- 3000 amp 12kV main breakers for each T1 & T2 transformer, redesign and upgrade primary to allow one transformer to support the full load of the substation in case of failure of the other transformer, upgrade protection and control to current standards.	$ 451,488		$ -
UDSNRD71D	Christiana District Emergency Repair/Replacements Distribution Sub Equipmen		$ -	Funds set aside for contingencies across distribution substations in Delaware	$ 235,656

Adjustment 26 Reliability and Non-Reliability Enhancement Projects

WBS Element	Project Description	REP Projects		Non-REP Projects	
		Detailed Description	Amount	Detailed Description	Amount
UDSNRD8AD	Christiana District Substation Planned Improvements		$ -	Blanket project - Planned capital improvements including control house upgrades, roof replacements, and cable troughs, etc in Delaware.	$ 98,046
UDSNRD8BD	Christiana District Misc Relay Blanket		$ -	No Description Provided	$ 61,416
UDSNRD8ED	Christiana District Distribution Substation Battery Replacements		$ -	No Description Provided	$ 103,071
UDSNRD8FD	Christiana District Distribution Substation Bushing Replacements		$ -	Replace bushing sets on transformers, in which the bushings have deteriorated or have not met testing specifications. Recommend replacing Type "U" or as identified by Maintenance testing data. Estimate based on 4 projects per year for 2013-2014, then 3 projects per year 2015-2017.	$ 122,067
UDSNRD8G	Christiana District Spare Distribution Transformer		$ -	Purchase PHI Spare XFMRS for New Castle region: 69/34 kV, 56 MVA (2013 - June) 230/34 kV 100MVA (2014 - May) 138/34 kV 100MVA (2015 - May)	$ 1,125,158
UDSNRD8G1	Christiana District- Purchase 138/69 -12 kV Mobile XFMRs		$ -	Purchase 138/12.47 kV and 69/12.47 kV Mobile XFMRs 30-40 MVA for New Castle region Progress payment of approximately $1,200,000 planned to be made in 2012	$ 3,790,301
UDSNRD8GD	Christiana Substation. Upgrade #2 Transformer		$ -	Purchase Spare XFMR for Christiana Substation Transformer is on order with expected delivery and installation in Nov.- Dec 2012	$ 124,303
UDSNRD8MD	Christiana District Substations Upgrades to SCADA/RTU	SCADA and RTU equipment is obsolete and needs to be upgraded and replaced: Christiana A&B; Edge Moor 69kV; Harmony; Brookside; Glasgow; Milltown; Naamans; New Castle; Point Breeze; Talleyville; W.Wilmington	$ 304,055		$ -
UDSNRD8PD	Christiana District Reg Distribution Substation Misc Equip Retirement		$ -	No Description Provided	$ 24,514
UDSNRD8SA	Churchmans Substation RECLOSER REMOVAL		$ -	No Description Provided	$ 46,219
UDSNRD8SE	substation - Replace Failed #3 Transformer		$ -	No Description Provided	$ 264,849
UDSNRD8SI	Chapel Street Substation - Resupply Station Service		$ -	No Description Provided	$ 88,077
UDSNRD8VD	Christiana District Installation Cyber Security Improvements		$ -	Installation of Physical Security Systems at Identified Distribution Substations. Above and Beyond Security scope includes: 1. Card Access and Exit Readers on gates and Control House doors 2. Alarms 3. Future Sentry camera systems with Solar Power solution.	$ 784,420

Adjustment 26 Reliability and Non-Reliability Enhancement Projects

WBS Element	Project Description	REP Projects		Non-REP Projects	
		Detailed Description	Amount	Detailed Description	Amount
UDSNRD9DD	Christiana District Distribution Substation Breaker Replacements		$ -	Replace deteriorated distribution breakers: West Substation, others yet to be planned. ~16 breakers per year until 2015.	$ 1,399,999
UDSNRD9FD	Christiana District REPLACE/UPGRADE Potential Transformers		$ -	Replace Deteriorated distribution potential transformers in New Castle Region in Delaware. These Pt's are low or leaking oil	$ 69,201
UDSNRD9HD	Christiana District Replace 34.5kV Capacitor Banks		$ -	Replace entire capacitor bank at Darley Substation	$ 287,052
UDSNRD9KA	Milford Crossroads Substation 12kV Switchgear Replacement	Replace Switchgear #1 and #2 Install control house, control enclosure, or add additional compartments onto switchgear to house all relay and control equipment.	$ 1,818,831		$ -
UDSNRD9KB	Bear Substation – 12kV Switchgear Replacement	Replace Switchgear #1 and #2 Remove bus duct bus tie and replace with underground cable Add main breakers to both switchgear line-ups Install controll house to house all control and relay equipment	$ 1,699,117		$ -
UDSNRD9SE	Edge Moor Substation- Upgrade 12kV Main Breakers		$ -	Upgrade the 7 seven(7) obsolete 1950's vintage high current, high fault interrupting air blast General Electric 4000 amp, 60KA 14.4kV GE air blast circuit breakers These breakers are located at Edge Moor 12kV yard and now supply only the Calpine Edge Moor plant. Calpine will be reimbursing PHI partially on 5 breakers in 2012 in accordance with the agreement.	$ 207,818
UDSNRD9SH	Brookside Substation - Upgrade #2 Transformer		$ -	Replace Brookside T2 with a new 34/12kV 20 MVA transformer. The new arrangement will be located within the Brookside Substation. Include a high side 34kV breaker for T2. The new arrangement will include 12kV breakers that can accommodate 1 future circuit and a mobile position. T2 should be placed in order to allow for installation of a second feeder from T2 in the future. Also provide necessary protection equipment.	$ 2,080,135
UDSNRD9SJ	Christiana District MILFORD CROSSROADS T2 UPGRADE		$ -	Replace Milford Crossroads T-2 Transformer with a new 34/12 kV 20MVA transformer Direct Replacement Transformer is on order now and 3 progress payments expected to be made in 2012	$ 389,772
UDSNRD9SK	West Substation - Replace T-2 69/34 kV 18 MVA Transformer		$ -	Replace West Substation T-2 Transformer with a new 69/34.5 kV 30/40/50 MVA transformer	$ 1,079,066
UDSNRD9ZD	Christiana District Replace Deteriorated Switches		$ -	No Description Provided	$ 72,788
UDSNRDA1C	Christiana District Distribution Automation: Christiana Substations	Replace Identified Feeder Relays with SEL451 Front Line and SEL551 Backup on feeders either in Switchgear or in Control House as necessary. Also Install RTU/Communication Panel one in every substation being done having OrionLX, ethernet switches, GPS Clock and a Computer to communicate.	$ 823,379		$ -

Adjustment 26 Reliability and Non-Reliability Enhancement Projects

WBS Element	Project Description	REP Projects		Non-REP Projects	
		Detailed Description	Amount	Detailed Description	Amount
UDSNRM61D	Christiana District Substation Reliability Equipment & Design Improvements	This WBS includes the switchgear projects Darley, Silverside and Point Breeze started in 2012, which will finish Jan-March of 2012.	$ 547,709		$ -
UDSNRMT2	640		$ -	No Description Provided	$ 91,185
UOIBRASRD	Millsboro District, Distribution Automation Automatic Sectionalizing and Restoration Equipment Installation	No Description Provided	$ 7,843		$ -
UOINRASRD	Christiana District, Distribution Automation Automatic Sectionalizing and Restoration Equipment Installation	In identified New Castle Substations where Distribution Automation work is being completed, the ASR computer shall be installed.	$ 223,263		$ -
UORBORBSM	Automation Communication Work Install Broad Band Wireless Base Station	Project will provide for the installation of Broadband Wireless base station radios and supporting hardware in the Millsboro district.	$ 168,270		$ -
UORBORCPM	Millsboro District Distribution Automation Communication Work Install - Capiactor Controls	Install SSN or other (i.e. 220MHz) radios in switched Capacitor Control Equipment in Millsboro District in order to establish communcations between the Capacitor Control and the centralized VAR management system.	$ 19,270		$ -
UORBORSSM	Millsboro District Distribution Automation Communication Work Install Broad Band Wireless Substation Subscriber Radios	Project will provide for the installation of Broadband Wireless subscriber radios and supporting hardware in the Millsboro district substations.	$ 145,734		$ -
UORNOBR1C	Christiana District Distribution Automation Communication Work - Collector to Data Network	Project will provide for the installation of broadband wireless subscriber radios and supporting hardware to backhaul communications between remote DA and AMI applications and the backbone network in Christiana district.	$ 313,986		$ -
UORNODA1C	Christiana District Distribution Automation Communication Work - Install Radios in Line Equipment	Project will provide for the installation of Silver Spring Networks eBridge radios in line equipment, including reclosers, switches, and capacitor banks in the Christiana District.	$ 437,553		$ -
UORNORBSC	Christiana District Distribution Automation Communication Work Install Broad Band Wireless Base Station	Project will provide for the installation of Broadband Wireless base stations and supporting hardware in the Christiana district substations.	$ 314,067		$ -
UORNORSSC	Christiana District Distribution Automation Communication Work Install Broad Band Wireless Substation Subscriber Radios	Project will provide for the installation of Broadband Wireless subscriber radios and supporting hardware in the Christiana district substations.	$ 330,325		$ -
Total			$ 35,193,494		$39,763,315

Source: David E. Dismukes, Direct Testimony, Schedule DED-7; Company's Response to Data Request PSC-REL-8, Attachments A and B.

Comparison of CCOSS Allocation Factors

FERC Account	Description	Recommended Factor	Delmarva Factor Description
RATE BASE			
Intangible Plant			
302	Franchises & Consents	Total Distribution Plant	Total Distribution Plant
303	Miscellaneous Intangible Plant	Total Distribution Plant	Total Distribution Plant
Distribution Plant			
360.1	Land & Land Rights	Account 362 Station Equipment	Account 362 Station Equipment
360.1	Land & Land Rights - DA GST	Direct Assignment: General Service - Transmission	Direct Assignment: General Service - Transmission
360.2	Land & Land Rights	Accounts 364 - 367 Distribution Plant	Accounts 364 - 367 Distribution Plant
361	Structures & Improvements	Class NCP	Class NCP
361	Structures & Improvements - DA GSP	Direct Assignment: General Service - Primary	Direct Assignment: General Service - Primary
361	Structures & Improvements - DA GST	Direct Assignment: General Service - Transmission	Direct Assignment: General Service - Transmission
362	Station Equipment	Class NCP	Class NCP
362	Station Equipment - DA GSP	Direct Assignment: General Service - Primary	Direct Assignment: General Service - Primary
362	Station Equipment - DA GST	Direct Assignment: General Service - Transmission	Direct Assignment: General Service - Transmission
364	Poles, Towers and Fixtures		
	Poles, Towers and Fixtures - Primary Voltage	Class NCP	Class NCP
	Poles, Towers and Fixtures - Secondary Voltage	50% Class NCP (Excluding Primary and Large Secondary GS) & 50% Sum of Individual Customer Max Annual Demands	50% Class NCP (Excluding Primary and Large Secondary GS) & 50% Sum of Individual Customer Max Annual Demands
365	Overhead Conductors and Devices		
	Overhead Conductors and Devices - Primary Voltage	Class NCP	Class NCP
	Overhead Conductors and Devices - Secondary Voltage	50% Class NCP (Excluding Primary and Large Secondary GS) & 50% Sum of Individual Customer Max Annual Demands	50% Class NCP (Excluding Primary and Large Secondary GS) & 50% Sum of Individual Customer Max Annual Demands
366	Underground Conduit		
	Underground Conduit - Primary Voltage	Class NCP	Class NCP
	Underground Conduit - Secondary Voltage	50% Class NCP (Excluding Primary and Large Secondary GS) & 50% Sum of Individual Customer Max Annual Demands	50% Class NCP (Excluding Primary and Large Secondary GS) & 50% Sum of Individual Customer Max Annual Demands
367	Underground Conductors and Devices		
	Underground Conductors and Devices - Primary Voltage	Class NCP	Class NCP
	Underground Conductors and Devices - Secondary Voltage	50% Class NCP (Excluding Primary and Large Secondary GS) & 50% Sum of Individual Customer Max Annual Demands	50% Class NCP (Excluding Primary and Large Secondary GS) & 50% Sum of Individual Customer Max Annual Demands
368	Lines Transformers	50% Class NCP & 50% Sum of Individual Customer Max Annual Demands	50% Class NCP & 50% Sum of Individual Customer Max Annual Demands
369.1	Services	Sum of Individual Customer Max Annual Demands (Excludes Primary, Telecommunications, and Street Lighting)	Sum of Individual Customer Max Annual Demands (Excludes Primary, Telecommunications, and Street Lighting)
369.2	Services	Sum of Individual Customer Max Annual Demands (Excludes Primary, Telecommunications, and Street Lighting)	Sum of Individual Customer Max Annual Demands (Excludes Primary, Telecommunications, and Street Lighting)
370	Meters	Embedded Cost of Meters Study	Embedded Cost of Meters Study
371.2	Installations on Customer Premises	Street Lighting Direct Assignment	Street Lighting Direct Assignment
371.3	Installations on Customer Premises	Demand Side Management Costs	Demand Side Management Costs
373	Street Lighting and Signal Systems	Street Lighting Direct Assignment	Street Lighting Direct Assignment
General Plant			
389	Land & Land Rights	Total Distribution Plant	Labor Allocator
390	Structures and Improvements	Total Distribution Plant	Labor Allocator
391	Office Furniture & Equipment	Total Distribution Plant	Labor Allocator
392	Transportation Equipment	Total Distribution Plant	Labor Allocator
393	Stores Equipment	Total Distribution Plant	Labor Allocator
394	Tools, Shop and Garage Equipment	Total Distribution Plant	Labor Allocator
395	Laboratory Equipment	Total Distribution Plant	Labor Allocator
396	Power Operated Equipment	Total Distribution Plant	Labor Allocator
397	Communication Equipment	Total Distribution Plant	Labor Allocator
398	Misc. Equipment	Total Distribution Plant	Labor Allocator
399	Other Tangible Property	Total Distribution Plant	Labor Allocator

Comparison of CCOSS Allocation Factors

FERC Account	Description	Recommended Factor	Delmarva Factor Description
Common Plant			
C389.1	Land & Land Rights	Total Distribution Plant	Labor Allocator
C390.3	Structures and Improvements	Total Distribution Plant	Labor Allocator
C391	Office Furniture & Equipment	Total Distribution Plant	Labor Allocator
C393	Stores Equipment	Total Distribution Plant	Labor Allocator
C394	Tools, Shop and Garage Equipment	Total Distribution Plant	Labor Allocator
C397	Communication Equipment	Total Distribution Plant	Labor Allocator
C398	Misc. Equipment	Total Distribution Plant	Labor Allocator
Misc. Intangible Plant - Common			
301	Organization	Total Distribution Plant	Total Distribution Plant
303	Miscellaneous Intangible Plant	Total Distribution Plant	Total Distribution Plant
303.107	Software 10 Year	Labor Allocator	Labor Allocator
	Service Company Assets	Labor Allocator	Labor Allocator
	AMI IT Hardware & Software	AMI Allocator	AMI Allocator
Depreciation Reserve			
	Distribution Plant - Delaware	Total Distribution Plant	Total Distribution Plant
	General Plant	Total General Plant	Total General Plant
	Intangible Plant	Total Intangible Plant	Total Intangible Plant
	Common Intangible (Electric @ 84%)	Total Common Intangible Plant	Total Common Intangible Plant
	Common (Electric @ 84%)	Total Common General Plant	Total Common General Plant
	Service Company Assets	Service Company Assets	Service Company Assets
	AMI IT Hardware & Software	AMI Allocator	AMI Allocator
Construction Work in Progress (CWIP)			
	Distribution Plant - Delaware	Total Distribution Plant	Total Distribution Plant
	General Plant	Total General Plant	Total General Plant
	Other	Total Distribution Plant	Total Distribution Plant
	Common (Electric @ 84%)	Total Common General Plant	Total Common General Plant
	Service Company Assets	Service Company Assets	Service Company Assets

Comparison of CCOSS Allocation Factors

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FERC Account	Description	Recommended Factor	Delmarva Factor Description
Other Rate Base Items			
Plant Held for Future Use			
	Distribution Plant - Delaware	Total Distribution Plant	Total Distribution Plant
	General Plant	Total General Plant	Total General Plant
Materials & Supplies			
	Distribution Plant - Delaware	Total Distribution Plant	Total Distribution Plant
	Labor Stock	Labor Allocator	Labor Allocator
Cash Working Capital			
	O&M - Distribution	Total O&M Expenses	Total O&M Expenses
	Payroll Taxes	Labor Allocator	Labor Allocator
	Franchise Taxes - Delaware	Total Plant (Intangible, Distribution, General, Common, Misc. Intangible Plant)	Total Plant (Intangible, Distribution, General, Common, Misc. Intangible Plant)
	Local Taxes - Delaware	Sales Revenue	Sales Revenue
	Property Taxes - Delaware	Total Plant (Intangible, Distribution, General, Common, Misc. Intangible Plant)	Total Plant (Intangible, Distribution, General, Common, Misc. Intangible Plant)
	Federal Income Tax	Taxable Income	Taxable Income
	State Income Tax	Taxable Income	Taxable Income
	Interest Expense	Total Plant (Intangible, Distribution, General, Common, Misc. Intangible Plant)	Total Plant (Intangible, Distribution, General, Common, Misc. Intangible Plant)
	Interest On Customer Deposits	Total Customer Deposits	Total Customer Deposits
Misc.			
	Prepaid Insurance	Labor Allocator	Labor Allocator
	OPEB Liability	Labor Allocator	Labor Allocator
	IRP Regualtory Asset (DE)	Total Plant (Intangible, Distribution, General, Common, Misc. Intangible Plant)	Total Plant (Intangible, Distribution, General, Common, Misc. Intangible Plant)
	FRP Regulatory Asset (DE)	Total Plant (Intangible, Distribution, General, Common, Misc. Intangible Plant)	Total Plant (Intangible, Distribution, General, Common, Misc. Intangible Plant)
	AMI Regulatory Asset (DE)	AMI Allocator	AMI Allocator
	Prepaid Pension	Labor Allocator	Labor Allocator
Accumulated ITC			
	Distribution Plant - Delaware	Total Distribution Plant	Total Distribution Plant
	General Plant	Total General Plant	Total General Plant
	Common Plant	Total Common Plant	Total Common Plant
Customer Advances		Total Distribution Plant	Total Distribution Plant
Customer Deposits			
	Delaware Residential	Residential Direct Assignment	Residential Direct Assignment
	Delaware Non-Residential	Total Distribution Plant (Non-Residential)	Total Distribution Plant (Non-Residential)
Deferred Federal and State Income Taxes			
	Labor	Labor Allocator	Labor Allocator
	Plant	Total Plant (Intangible, Distribution, General, Common, Misc. Intangible Plant)	Total Plant (Intangible, Distribution, General, Common, Misc. Intangible Plant)
	Uncollectible Expense	Uncollectible Accounts Revenues	Uncollectible Accounts Revenues

Comparison of CCOSS Allocation Factors

FERC Account	Description	Recommended Factor	Delmarva Factor Description
OPERATIONS AND MAINTENANCE EXPENSES			
Distribution Expense			
Operations Expenses			
580	Supervision and Engineering	Accounts 958.1 - 958.7 Distribution Operating Expenses (Labor Related Expenses)	Accounts 958.1 - 958.7 Distribution Operating Expenses (Labor Related Expenses)
581	Load Dispatching	Total Sales Excluding Transmission	Total Sales Excluding Transmission
582	Station Expenses	Account 362 Station Equipment	Account 362 Station Equipment
583	Overhead Line Expenses	Accounts 364 & 365 Overhead Lines	Accounts 364 & 365 Overhead Lines
584	Underground Line Expenses	Accounts 366 & 367 Underground Lines	Accounts 366 & 367 Underground Lines
585	Street Lighting	Account 373 Street Lighting and Signal Systems	Account 373 Street Lighting and Signal Systems
586	Meter Expenses	Account 370 Meters	Account 370 Meters
587	Customer Installations Expenses	Account 369 Services	Account 369 Services
588	Miscellaneous	Accounts 958.1 - 958.7 Distribution Operating Expenses (Non-Labor Expenses)	Accounts 958.1 - 958.7 Distribution Operating Expenses (Non-Labor Expenses)
589	Rents	Accounts 958.1 - 958.7 Distribution Operating Expenses (Non-Labor Expenses)	Accounts 958.1 - 958.7 Distribution Operating Expenses (Non-Labor Expenses)
Maintenance Expenses			
590	Supervision & Engineering	Accounts 959.2 - 959.7 Distribution Maintenance Expenses (Labor Related Expenses)	Accounts 959.2 - 959.7 Distribution Maintenance Expenses (Labor Related Expenses)
592	Station Expenses	Account 362 Station Equipment	Account 362 Station Equipment
593	Overhead Line Expenses	Accounts 364 & 365 Overhead Lines	Accounts 364 & 365 Overhead Lines
594	Underground Line Expenses	Accounts 366 & 367 Underground Lines	Accounts 366 & 367 Underground Lines
595	Line Transformers	Account 368 Line Transformers	Account 368 Line Transformers
596	Street Lighting & Signal Systems	Account 373 Street Lighting and Signal Systems	Account 373 Street Lighting and Signal Systems
597	Meters	Account 370 Meters	Account 370 Meters
598	Distribution Plant	Accounts 959.2 - 959.7 Distribution Maintenance Expenses (Non-Labor Expense)	Accounts 959.2 - 959.7 Distribution Maintenance Expenses (Non-Labor Expense)
Customer Account Expense			
902	Meter Reading Expenses	Meter Reading Study	Meter Reading Study
903	Customer Records & Collection	Customer Records and Collection Study	Customer Records and Collection Study
904	Uncollectible Accounts	Distribution Account Write-Offs	Distribution Account Write-Offs
Customer Service & Inform. Exp.			
907	Supervision	100% Number of Customers	50% Number of Customers & 50% Energy Sales
908	Customer Assistance Expenses	100% Number of Customers	50% Number of Customers & 50% Energy Sales
909	Information & Instruction Exp.	100% Number of Customers	50% Number of Customers & 50% Energy Sales
910	Miscellaneous	100% Number of Customers	50% Number of Customers & 50% Energy Sales
Sales Expenses			
912	Demonstrating & Selling Expenses	100% Number of Customers	50% Number of Customers & 50% Energy Sales
913	Advertising Expenses	100% Number of Customers	50% Number of Customers & 50% Energy Sales

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FERC Account	Description	Recommended Factor	Delmarva Factor Description
Administrative & General Expenses			
Operation Expenses			
920	A & G Salaries	Labor Allocator	Labor Allocator
921	Office Supplies & Expenses	Labor Allocator	Labor Allocator
923	Outside Services Employed	Labor Allocator	Labor Allocator
924	Property Insurance	Total Plant (Intangible, Distribution, General, Common, Misc. Intangible Plant)	Total Plant (Intangible, Distribution, General, Common, Misc. Intangible Plant)
925	Injuries & Damages	Labor Allocator	Labor Allocator
926	Employee Pensions & Benefits	Labor Allocator	Labor Allocator
928	Regulatory Commission Expense	Total Plant (Intangible, Distribution, General, Common, Misc. Intangible Plant)	Total Plant (Intangible, Distribution, General, Common, Misc. Intangible Plant)
928	Regulatory Tax Assessment	Labor Allocator	Labor Allocator
929	Duplicate Charges - Credit	Labor Allocator	Labor Allocator
930.1	General Administrative Expenses	Labor Allocator	Labor Allocator
930.2	Miscellaneous	Labor Allocator	Labor Allocator
930.2	Delaware Universal Service Program	Delaware Universal Service Program Revenues	Delaware Universal Service Program Revenues
931	Rents	Labor Allocator	Labor Allocator
Maintenance Expenses			
935	Maintenance of General Plant	Total General Plant	Total General Plant
OTHER COST OF SERVICE COMPONENTS			
Depreciation Expense			
	Distribution Plant	Total Distribution Plant	Total Distribution Plant
	General Plant	Total General Plant	Total General Plant
	Common Plant	Total Common Plant	Total Common Plant
Amortization Expense			
	Lease Vehicles	Labor Allocator	Labor Allocator
	Delaware IRP Recovery	Total Plant (Intangible, Distribution, General, Common, Misc. Intangible Plant)	Total Plant (Intangible, Distribution, General, Common, Misc. Intangible Plant)
	Delaware RFP Recovery	Total Plant (Intangible, Distribution, General, Common, Misc. Intangible Plant)	Total Plant (Intangible, Distribution, General, Common, Misc. Intangible Plant)
	Intangible - Software	Labor Allocator	Labor Allocator

Comparison of CCOSS Allocation Factors

FERC Account	Description	Recommended Factor	Delmarva Factor Description
Taxes Other Than Income Taxes			
	Payroll Taxes	Labor Allocator	Labor Allocator
	Property Taxes	Total Plant (Intangible, Distribution, General, Common, Misc. Intangible Plant)	Total Plant (Intangible, Distribution, General, Common, Misc. Intangible Plant)
	Franchise Taxes	Total Plant (Intangible, Distribution, General, Common, Misc. Intangible Plant)	Total Plant (Intangible, Distribution, General, Common, Misc. Intangible Plant)
	Local Taxes	Sales Revenue	Sales Revenue
Net ITC Adjustment			
	Distribution Plant	Total Distribution Plant	Total Distribution Plant
	General Plant	Total General Plant	Total General Plant
	Common Plant	Total Common Plant	Total Common Plant
Interest on Customer Deposits			
	Delaware	Total Customer Deposits	Total Customer Deposits
AFUDC			
	Distribution Plant	Total Distribution Plant	Total Distribution Plant
	General Plant	Total General Plant	Total General Plant
	Common Plant	Total Common Plant	Total Common Plant
Other Operating Revenues			
	Interdepartmental Revenues	Sales Revenue	Sales Revenue
	Premise Collection Fee	Number of Customers	Number of Customers
	Late Payment Revenue	Distribution Account Write-Offs	Distribution Account Write-Offs
	Miscellaneous Service Revenue	Number of Customers	Number of Customers
	Special Facilities Charge - GSP	Direct Assignment: General Service - Primary	Direct Assignment: General Service - Primary
	Special Facilities Charge - GST	Direct Assignment: General Service - Transmission	Direct Assignment: General Service - Transmission
	Miscellaneous Service Revenue - DA GST	Direct Assignment: General Service - Transmission	Direct Assignment: General Service - Transmission
	Rent from Electric Property	Total Distribution Plant	Total Distribution Plant

Source: Company's Class Cost of Service Study.

Comparison of Class Rates of Return Under Company's and Recommended Cost Allocation Factors

Service Class	Company's CCOSS Under Present Rates	Company's CCOSS Under Proposed Rates	Recommended CCOSS Under Present Rates	Recommended CCOSS Under Proposed Rates
Residential	4.34%	10.45%	4.18%	6.85%
Residential Space Heating	2.68%	8.66%	2.52%	4.31%
General Service Secondary Small	9.38%	17.99%	9.52%	13.85%
General Service Secondary Large	4.54%	10.25%	4.71%	7.44%
General Service Primary	1.77%	7.39%	2.44%	4.27%
General Service Transmission	-4.23%	0.82%	14.01%	20.61%
Street Lighting Service	4.98%	10.52%	4.46%	6.94%

Source: Elliott P. Tanos, Direct Testimony, Schedule (EPT)-1; Marlene C. Santacecilia, Direct Testimony, Schedule (MCS)-1.

CCOSS Under Recommended Cost Allocation Factors

	Total Delaware Retail	Residential Service	General Service Secondary	General Service Primary	General Service Transmission	Street Lighting Service
RATE BASE						
Total System Electric Distribution	$ 1,106,124,352	$ 681,336,265	$ 212,557,869	$ 126,682,971	$ 906,593	$ 84,640,654
Less: Depreciation Reserve	$ 408,440,153	$ 251,256,011	$ 78,571,469	$ 47,407,500	$ 333,607	$ 30,871,566
Total Net Plant	$ 697,684,198	$ 430,080,253	$ 133,986,401	$ 79,275,470	$ 572,985	$ 53,769,088
ADD:						
CWIP	$ 70,154,772	$ 43,100,635	$ 13,511,553	$ 8,284,711	$ 56,939	$ 5,200,934
Working Capital	$ 10,887,807	$ 6,925,354	$ 2,076,154	$ 1,451,510	$ 45,719	$ 389,070
Materials & Supplies	$ 18,164,174	$ 11,167,117	$ 3,496,061	$ 2,123,453	$ 14,802	$ 1,362,741
Miscellaneous Rate Base Items	$ 57,392,849	$ 34,347,855	$ 11,327,535	$ 9,376,260	$ 39,347	$ 2,301,851
DEDUCT:						
Accumulated ITC	$ 1,853,616	$ 1,142,372	$ 355,964	$ 209,486	$ 1,529	$ 144,265
Customer Advances	$ 1,651,163	$ 1,017,601	$ 317,086	$ 186,606	$ 1,362	$ 128,508
Customer Deposits	$ 13,702,572	$ 9,228,734	$ 2,239,072	$ 1,317,699	$ 9,619	$ 907,448
Deferred FIT	$ (135,140,550)	$ (83,064,432)	$ (26,044,385)	$ (15,532,078)	$ (111,307)	$ (10,388,349)
Deferred SIT	$ (27,021,001)	$ (16,597,541)	$ (5,212,149)	$ (3,108,971)	$ (22,289)	$ (2,080,050)
TOTAL RATE BASE	$ 674,914,898	$ 414,570,535	$ 130,229,047	$ 80,156,565	$ 583,688	$ 49,375,064
DEVELOPMENT OF RETURN						
Revenue - Retail Sales	$ 172,900,083	$ 103,098,643	$ 40,836,144	$ 19,723,846	$ 476,853	$ 8,764,597
Interdepartmental	$ 58,423	$ 36,734	$ 10,939	$ 7,423	$ 148	$ 3,178
Other Operating Revenue	$ 3,840,358	$ 2,687,467	$ 558,091	$ 270,176	$ 122,151	$ 202,473
Total Electric Operating Revenue	$ 176,798,863	$ 105,822,844	$ 41,405,174	$ 20,001,445	$ 599,151	$ 8,970,248
LESS:						
Operating & Maintenance Expense	$ 103,201,264	$ 66,423,934	$ 18,753,231	$ 14,044,120	$ 442,411	$ 3,537,568
Depreciation & Amortization Expense	$ 28,293,088	$ 17,435,361	$ 5,433,797	$ 3,201,920	$ 23,328	$ 2,198,683
Other Taxes	$ 7,973,607	$ 4,881,746	$ 1,540,496	$ 997,582	$ 6,648	$ 547,134
Net ITC Adjustment	$ (250,890)	$ (154,622)	$ (48,180)	$ (28,354)	$ (207)	$ (19,526)
Interest on Customer Deposits	$ 14,967	$ 10,080	$ 2,446	$ 1,439	$ 11	$ 991
Income Taxes	$ 8,377,793	$ 2,755,416	$ 5,067,542	$ (61,042)	$ 45,956	$ 569,922
Total Operating Expenses	$ 147,609,829	$ 91,351,915	$ 30,749,331	$ 18,155,664	$ 518,146	$ 6,834,773
PLUS: AFUDC	$ 965,309	$ 594,914	$ 185,376	$ 109,094	$ 796	$ 75,129
OPERATING INCOME	$ 30,154,343	$ 15,065,844	$ 10,841,219	$ 1,954,875	$ 81,801	$ 2,210,604
RATE OF RETURN	4.47%	3.63%	8.32%	2.44%	14.01%	4.48%
RELATIVE RATE OF RETURN	1.00	0.81	1.86	0.55	3.14	1.00

CCOSS Under Recommended Cost Allocation Factors

	Total Delaware Retail	Residential Service	General Service Secondary	General Service Primary	General Service Transmission	Street Lighting Service
ELECTRIC PLANT IN SERVICE						
DISTRIBUTION PLANT						
Distribution - Delaware						
3601 Land and Land Rights	$ 3,380,182	$ 1,824,701	$ 735,031	$ 780,616	$ 13,652	$ 26,181
3601 Land and Land Rights	$ 1,657	$ -	$ -	$ -	$ 1,657	$ -
3602 Land and Land Rights	$ 3,536,923	$ 2,097,547	$ 763,969	$ 647,572	$ -	$ 27,835
3610 Structures and Improvements	$ 15,377,345	$ 8,438,206	$ 3,399,100	$ 3,418,966	$ -	$ 121,074
3610 Structures and Improvements DA GSP	$ 72,487	$ -	$ -	$ 72,487	$ -	$ -
3610 Structures and Improvements DA GST	$ 5,670	$ -	$ -	$ -	$ 5,670	$ -
3620 Station Equipment	$ 138,910,960	$ 76,226,375	$ 30,705,703	$ 30,885,166	$ -	$ 1,093,717
3620 Station Equipment DA GSP	$ 1,724,856	$ -	$ -	$ 1,724,856	$ -	$ -
3620 Station Equipment DA GST	$ 570,326	$ -	$ -	$ -	$ 570,326	$ -
Total Acct 3620	$ 141,206,142	$ 76,226,375	$ 30,705,703	$ 32,610,022	$ 570,326	$ 1,093,717
3640 Poles, Towers and Fixtures						
Demand Primary	$ 52,213,852	$ 28,651,970	$ 11,541,659	$ 11,609,116	$ -	$ 411,106
Demand Secondary	$ 10,168,289	$ 8,131,533	$ 1,956,901	$ -	$ -	$ 79,855
Total Acct 3640	$ 62,382,140	$ 36,783,502	$ 13,498,561	$ 11,609,116	$ -	$ 490,961
3650 Overhead Conductors and Devices						
Demand Primary	$ 98,559,522	$ 54,083,818	$ 21,786,181	$ 21,913,513	$ -	$ 776,009
Demand Secondary	$ 19,193,790	$ 15,349,183	$ 3,693,871	$ -	$ -	$ 150,735
Total Acct 3650	$ 117,753,312	$ 69,433,001	$ 25,480,053	$ 21,913,513	$ -	$ 926,744
3660 Underground Conduit						
Demand Primary	$ 13,561,631	$ 7,441,846	$ 2,997,743	$ 3,015,264	$ -	$ 106,778
Demand Secondary	$ 3,179,057	$ 2,542,277	$ 611,814	$ -	$ -	$ 24,966
Total Acct 3660	$ 16,740,688	$ 9,984,123	$ 3,609,557	$ 3,015,264	$ -	$ 131,744
3670 Underground Conductors and Devices						
Demand Primary	$ 134,071,746	$ 73,570,892	$ 29,636,014	$ 29,809,225	$ -	$ 1,055,615
Demand Secondary	$ 31,428,496	$ 25,133,220	$ 6,048,458	$ -	$ -	$ 246,818
Total Acct 3670	$ 165,500,242	$ 98,704,112	$ 35,684,472	$ 29,809,225	$ -	$ 1,302,433
3680 Line Transformers	$ 206,854,875	$ 152,623,396	$ 52,754,210	$ -	$ -	$ 1,477,270
3691 Services	$ 13,875,916	$ 12,745,640	$ 1,130,276	$ -	$ -	$ -
3692 Services	$ 74,811,527	$ 68,717,681	$ 6,093,846	$ -	$ -	$ -
3700 Metering Equip/Transformers	$ 15,119,144	$ 3,099,383	$ 5,585,454	$ 6,150,431	$ 212,159	$ 71,717
3701 Meters AMI	$ 58,718,914	$ 51,073,994	$ 7,592,635	$ 40,378	$ -	$ 11,907
3712 Installations on Customer Premises	$ 22,434,167	$ -	$ -	$ -	$ -	$ 22,434,167
3713 Installations on Customer Premises	$ 8,496,920	$ 8,489,619	$ 2,980	$ 3,427	$ -	$ 894
3730 Street Lighting and Signal Systems	$ 47,685,013	$ -	$ -	$ -	$ -	$ 47,685,013
Total Distribution - Delaware	$ 973,953,266	$ 600,241,281	$ 187,035,846	$ 110,071,019	$ 803,464	$ 75,801,657

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	Total Delaware Retail	Residential Service	General Service Secondary	General Service Primary	General Service Transmission	Street Lighting Service
ELECTRIC PLANT IN SERVICE						
General Plant						
3891 Land and Land Rights	$ 773,588	$ 476,757	$ 148,558	$ 87,427	$ 638	$ 60,207
3903 Structures and Improvements	$ 12,666,366	$ 7,806,202	$ 2,432,421	$ 1,431,485	$ 10,449	$ 985,809
3911 Office Furniture and Equipment	$ 1,472,599	$ 907,553	$ 282,795	$ 166,425	$ 1,215	$ 114,611
3912 Office Furniture and Equipment	$ -	$ -	$ -	$ -	$ -	$ -
3913 Office Furniture and Equipment	$ 138,705	$ 85,483	$ 26,637	$ 15,676	$ 114	$ 10,795
3914 Office Furniture and Equipment	$ -	$ -	$ -	$ -	$ -	$ -
3920 Transportation Equipment	$ 194,304	$ 119,748	$ 37,314	$ 21,959	$ 160	$ 15,122
3930 Stores Equipment	$ 274,401	$ 169,112	$ 52,695	$ 31,011	$ 226	$ 21,356
3932 Stores Equipment	$ -	$ -	$ -	$ -	$ -	$ -
3940 Tools, Shop and Garage Equipment	$ 5,948,457	$ 3,665,997	$ 1,142,329	$ 672,263	$ 4,907	$ 462,962
3942 Tools, Shop and Garage Equipment	$ -	$ -	$ -	$ -	$ -	$ -
3950 Laboratory Equipment	$ 292,955	$ 180,546	$ 56,258	$ 33,108	$ 242	$ 22,800
3952 Laboratory Equipment	$ -	$ -	$ -	$ -	$ -	$ -
3970 Communication Equipment	$ 24,404,457	$ 15,040,314	$ 4,686,578	$ 2,758,062	$ 20,132	$ 1,899,371
3971 Communication Equipment	$ 1,533,863	$ 945,310	$ 294,560	$ 173,349	$ 1,265	$ 119,379
3973 Communication Equipment	$ 4,572,551	$ 2,818,034	$ 878,103	$ 516,765	$ 3,772	$ 355,876
3980 Miscellaneous Equipment	$ 380,658	$ 234,597	$ 73,101	$ 43,020	$ 314	$ 29,626
399 Other Tangible Property	$ 32,395	$ 19,965	$ 6,221	$ 3,661	$ 27	$ 2,521
3991 Other Tangible Property	$ 80,465	$ 49,590	$ 15,452	$ 9,094	$ 66	$ 6,263
Total General Plant	$ 52,765,765	$ 32,519,209	$ 10,133,021	$ 5,963,306	$ 43,529	$ 4,106,698
Intangible Plant						
3020 010 Franchises and Consents	$ 313	$ 193	$ 60	$ 35	$ 0	$ 24
3020 020 Franchises and Consents	$ 960	$ 592	$ 184	$ 109	$ 1	$ 75
3020 030 Franchises and Consents	$ -	$ -	$ -	$ -	$ -	$ -
3030 000 Miscellaneous Intangible Plant	$ 2,935,378	$ 1,809,055	$ 563,704	$ 331,741	$ 2,422	$ 228,457
3030 010 Miscellaneous Intangible Plant	$ 5,677,924	$ 3,499,269	$ 1,090,376	$ 641,689	$ 4,684	$ 441,906
3030 020 Miscellaneous Intangible Plant	$ 228,795	$ 141,005	$ 43,937	$ 25,857	$ 189	$ 17,807
Total Intangible Plant	$ 8,843,369	$ 5,450,113	$ 1,698,261	$ 999,431	$ 7,295	$ 688,269

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	Total Delaware Retail	Residential Service	General Service Secondary	General Service Primary	General Service Transmission	Street Lighting Service
ELECTRIC PLANT IN SERVICE						
Common Plant						
C3891 Land and Land Rights	$ 894,237	$ 551,113	$ 171,727	$ 101,062	$ 738	$ 69,597
C3903 Structures and Improvements	$ 22,522,987	$ 13,880,776	$ 4,325,265	$ 2,545,428	$ 18,580	$ 1,752,938
C3911 Office Furniture and Equipment	$ 3,053,187	$ 1,881,660	$ 586,327	$ 345,055	$ 2,519	$ 237,626
C3912 Office Furniture and Equipment	$ -	$ -	$ -	$ -	$ -	$ -
C3913 Office Furniture and Equipment	$ 1,021,648	$ 629,635	$ 196,195	$ 115,461	$ 843	$ 79,514
C3914 Office Furniture and Equipment	$ -	$ -	$ -	$ -	$ -	$ -
C3930 Stores Equipment	$ 105,989	$ 65,321	$ 20,354	$ 11,978	$ 87	$ 8,249
C3932 Stores Equipment	$ -	$ -	$ -	$ -	$ -	$ -
C3940 Tools, Shop and Garage Equipment	$ 1,988,850	$ 1,225,716	$ 381,934	$ 224,769	$ 1,641	$ 154,790
C3942 Tools, Shop and Garage Equipment	$ -	$ -	$ -	$ -	$ -	$ -
C3970 Communication Equipment	$ 9,520,504	$ 5,867,427	$ 1,828,297	$ 1,075,957	$ 7,854	$ 740,970
C3971 Communication Equipment	$ 116,841	$ 72,008	$ 22,438	$ 13,205	$ 96	$ 9,094
C3980 Miscellaneous Equipment	$ 1,059,211	$ 652,785	$ 203,409	$ 119,706	$ 874	$ 82,437
C3982 Miscellaneous Equipment	$ -	$ -	$ -	$ -	$ -	$ -
Total Common - General	$ 40,283,455	$ 24,826,440	$ 7,735,946	$ 4,552,622	$ 33,232	$ 3,135,215
Misc. Intangible						
3010 Organization	$ 400,455	$ 246,798	$ 76,902	$ 45,257	$ 330	$ 31,167
3031 070 Software 10 Year	$ 9,492,184	$ 5,647,799	$ 1,880,912	$ 1,594,905	$ 6,481	$ 362,087
3030 070 Miscellaneous Intangible Plant	$ -	$ -	$ -	$ -	$ -	$ -
C3030 Miscellaneous Intangible Plant	$ 1,638,819	$ 1,009,994	$ 314,715	$ 185,211	$ 1,352	$ 127,547
Total Common - Intangible	$ 11,531,457	$ 6,904,591	$ 2,272,530	$ 1,825,373	$ 8,163	$ 520,801
Total Electric Common @ 84%	$ 43,524,526	$ 26,654,066	$ 8,407,120	$ 5,357,516	$ 34,772	$ 3,071,053
Total pre-Service Co Electric Plant In Service	$ 1,079,086,926	$ 664,864,669	$ 207,274,248	$ 122,391,271	$ 889,060	$ 83,667,678
Service Company Assets	$ 25,499,805	$ 15,172,250	$ 5,052,883	$ 4,284,554	$ 17,410	$ 972,710
AMI IT Hardware & Software	$ 1,537,620	$ 1,299,346	$ 230,739	$ 7,146	$ 123	$ 266
Total System Electric Distribution	$ 1,106,124,352	$ 681,336,265	$ 212,557,869	$ 126,682,971	$ 906,593	$ 84,640,654

CCOSS Under Recommended Cost Allocation Factors

	Total Delaware Retail	Residential Service	General Service Secondary	General Service Primary	General Service Transmission	Street Lighting Service
DEPRECIATION RESERVE						
Distribution - Delaware	$ 332,955,907	$ 205,198,634	$ 63,940,121	$ 37,628,906	$ 274,672	$ 25,913,573
General	$ 17,296,068	$ 10,659,458	$ 3,321,499	$ 1,954,710	$ 14,268	$ 1,346,133
Intangible	$ 8,767,140	$ 5,403,133	$ 1,683,622	$ 990,815	$ 7,232	$ 682,336
Common Intangible (Electric @ 84%)	$ 9,350,042	$ 5,598,444	$ 1,842,633	$ 1,480,066	$ 6,619	$ 422,281
Common (Electric @ 84%)	$ 24,765,656	$ 15,262,918	$ 4,755,942	$ 2,798,883	$ 20,430	$ 1,927,482
Service Company Assets Reserve	$ 15,198,052	$ 9,042,760	$ 3,011,551	$ 2,553,622	$ 10,376	$ 579,741
AMI IT Hardware & Software	$ 107,290	$ 90,664	$ 16,100	$ 499	$ 9	$ 19
Total Depreciation Reserve	$ 408,440,153	$ 251,256,011	$ 78,571,469	$ 47,407,500	$ 333,607	$ 30,871,566
Total Net Plant	$ 697,684,198	$ 430,080,253	$ 133,986,401	$ 79,275,470	$ 572,985	$ 53,769,088
CWIP						
Distribution - Delaware	$ 30,778,211	$ 18,968,418	$ 5,910,580	$ 3,478,390	$ 25,391	$ 2,395,433
General	$ 22,426,048	$ 13,821,033	$ 4,306,649	$ 2,534,473	$ 18,500	$ 1,745,393
Other	$ 10,035,417	$ 6,181,487	$ 1,928,451	$ 1,149,343	$ 8,225	$ 767,910
Common (Electric @ 84%)	$ 716,062	$ 441,305	$ 137,511	$ 80,926	$ 591	$ 55,730
Service Company Assets	$ 6,199,034	$ 3,688,392	$ 1,228,362	$ 1,041,580	$ 4,232	$ 236,467
Total CWIP	$ 70,154,772	$ 43,100,635	$ 13,511,553	$ 8,284,711	$ 56,939	$ 5,200,934
MATERIALS & SUPPLIES						
Distribution	$ 16,880,097	$ 10,403,098	$ 3,241,617	$ 1,907,699	$ 13,925	$ 1,313,758
Labor Stock	$ 1,284,077	$ 764,019	$ 254,445	$ 215,754	$ 877	$ 48,982
Total Materials & Supplies	$ 18,164,174	$ 11,167,117	$ 3,496,061	$ 2,123,453	$ 14,802	$ 1,362,741
Cash Working Capital						
O&M - Distribution	$ 10,172,262	$ 6,547,223	$ 1,848,454	$ 1,384,290	$ 43,607	$ 348,688
Payroll Taxes	$ 147,298	$ 87,641	$ 29,188	$ 24,749	$ 101	$ 5,619
Franchise Taxes - Delaware	$ 31,423	$ 19,356	$ 6,038	$ 3,599	$ 26	$ 2,405
Utility Tax	$ 257,333	$ 161,804	$ 48,183	$ 32,697	$ 650	$ 14,000
Local Taxes - Delaware	$ 47,966	$ 30,160	$ 8,981	$ 6,095	$ 121	$ 2,610
Propery Tax - Delaware	$ 2,506,318	$ 1,543,810	$ 481,626	$ 287,045	$ 2,054	$ 191,784
FIT	$ 260,491	$ 195,998	$ (989)	$ 44,773	$ (363)	$ 21,071
SIT	$ (723,161)	$ (544,121)	$ 2,745	$ (124,296)	$ 1,008	$ (58,497)
Interest Expense	$ (1,806,777)	$ (1,112,915)	$ (347,199)	$ (206,928)	$ (1,481)	$ (138,255)
IOCD	$ (5,345)	$ (3,600)	$ (873)	$ (514)	$ (4)	$ (354)
Total Cash Working Capital	$ 10,887,807	$ 6,925,354	$ 2,076,154	$ 1,451,510	$ 45,719	$ 389,070

CCOSS Under Recommended Cost Allocation Factors

	Total Delaware Retail	Residential Service	General Service Secondary	General Service Primary	General Service Transmission	Street Lighting Service
MISC RATE BASE ITEMS						
Prepaid Insurance	$ 41,431	$ 24,651	$ 8,210	$ 6,961	$ 28	$ 1,580
OPEB Liability	$ (8,176,221)	$ (4,864,808)	$ (1,620,149)	$ (1,373,793)	$ (5,582)	$ (311,888)
IRP Regulatory Asset (DE)	$ 1,552,358	$ 956,202	$ 298,308	$ 177,790	$ 1,272	$ 118,786
RFP Regulatory Asset (DE)	$ 1,884,676	$ 1,160,898	$ 362,168	$ 215,849	$ 1,545	$ 144,215
AMI Regulatory Asset (DE)	$ 509,235	$ 430,322	$ 76,417	$ 2,367	$ 41	$ 88
Prepaid Pension	$ 61,581,370	$ 36,640,590	$ 12,202,581	$ 10,347,086	$ 42,044	$ 2,349,069
Total Misc Rate Base Items	$ 57,392,849	$ 34,347,855	$ 11,327,535	$ 9,376,260	$ 39,347	$ 2,301,851
ACCUMULATED ITC						
Distribution - Delaware	$ 1,676,524	$ 1,033,231	$ 321,956	$ 189,472	$ 1,383	$ 130,482
General	$ 55,103	$ 33,960	$ 10,582	$ 6,227	$ 45	$ 4,289
Common	$ 121,988	$ 75,180	$ 23,426	$ 13,786	$ 101	$ 9,494
Total Accumulated ITC	$ 1,853,616	$ 1,142,372	$ 355,964	$ 209,486	$ 1,529	$ 144,265
CUSTOMER ADVANCES						
Delaware	$ 1,651,163	$ 1,017,601	$ 317,086	$ 186,606	$ 1,362	$ 128,508
Total Customer Advances	$ 1,651,163	$ 1,017,601	$ 317,086	$ 186,606	$ 1,362	$ 128,508
CUSTOMER DEPOSITS						
Delaware	$ 9,228,734	$ 9,228,734	$ -	$ -	$ -	$ -
Delaware	$ 4,473,838	$ -	$ 2,239,072	$ 1,317,699	$ 9,619	$ 907,448
Total Customer Deposits	$ 13,702,572	$ 9,228,734	$ 2,239,072	$ 1,317,699	$ 9,619	$ 907,448
DEFERRED FIT						
Labor	$ 294,973	$ 175,507	$ 58,450	$ 49,562	$ 201	$ 11,252
Plant	$ (136,050,106)	$ (83,802,396)	$ (26,144,005)	$ (15,581,640)	$ (111,508)	$ (10,410,556)
Uncollectible Expense	$ 614,584	$ 562,458	$ 41,170	$ -	$ -	$ 10,956
Total Deferred FIT	$ (135,140,550)	$ (83,064,432)	$ (26,044,385)	$ (15,532,078)	$ (111,307)	$ (10,388,349)
DEFERRED SIT						
Labor	$ 77,197	$ 45,932	$ 15,297	$ 12,971	$ 53	$ 2,945
Plant	$ (27,259,041)	$ (16,790,674)	$ (5,238,221)	$ (3,121,942)	$ (22,342)	$ (2,085,862)
Uncollectible Expense	$ 160,842	$ 147,200	$ 10,775	$ -	$ -	$ 2,867
Total Deferred SIT	$ (27,021,001)	$ (16,597,541)	$ (5,212,149)	$ (3,108,971)	$ (22,289)	$ (2,080,050)
Total Rate Base	$ 674,914,898	$ 414,570,535	$ 130,229,047	$ 80,156,565	$ 583,688	$ 49,375,064

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	Total Delaware Retail	Residential Service	General Service Secondary	General Service Primary	General Service Transmission	Street Lighting Service
ELECTRIC SALES REVENUES						
Revenue - Retail Sales DE	$ 172,900,083	$ 103,098,643	$ 40,836,144	$ 19,723,846	$ 476,853	$ 8,764,597
INTERDEPARTMENTAL	$ 58,423	$ 36,734	$ 10,939	$ 7,423	$ 148	$ 3,178
REVENUE - OTHER						
Misc Other	$ -	$ -	$ -	$ -	$ -	$ -
Premise Collection Fee	$ 173,200	$ 151,783	$ 18,399	$ 280	$ 4	$ 2,734
Late Payment Revenue DE	$ 833,055	$ 762,399	$ 55,805	$ -	$ -	$ 14,851
Miscellaneous Service Revenue DE	$ 411,589	$ 360,693	$ 43,722	$ 666	$ 9	$ 6,498
Special Facilities Charge (Delaware) GSP	$ 10,192	$ -	$ -	$ 10,192	$ -	$ -
Special Facilities Charge (Delaware) GST	$ 120,246	$ -	$ -	$ -	$ 120,246	$ -
Miscellaneous Service Revenue DE DA GST	$ -	$ -	$ -	$ -	$ -	$ -
Rent from Electric Property DE	$ 2,292,075	$ 1,412,592	$ 440,165	$ 259,038	$ 1,891	$ 178,390
Total Other Revenue	$ 3,840,358	$ 2,687,467	$ 558,091	$ 270,176	$ 122,151	$ 202,473
Total Revenue	$ 176,798,863	$ 105,822,844	$ 41,405,174	$ 20,001,445	$ 599,151	$ 8,970,248

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	Total Delaware Retail	Residential Service	General Service Secondary	General Service Primary	General Service Transmission	Street Lighting Service
Distribution Expenses - DE						
Operation						
958000 Operation Supervision & Engineering	$ 4,534,354	$ 2,383,016	$ 993,479	$ 995,964	$ 3,722	$ 158,173
958100 Load dispatching	$ 2,559,904	$ 1,024,923	$ 666,415	$ 851,163	$ -	$ 17,404
958200 Station expenses	$ 516,665	$ 278,908	$ 112,350	$ 119,318	$ 2,087	$ 4,002
958300 Overhead line expenses	$ 1,081,762	$ 637,859	$ 234,077	$ 201,312	$ -	$ 8,514
958400 Underground line expenses	$ 1,000,294	$ 596,574	$ 215,679	$ 180,169	$ -	$ 7,872
958500 Street lighting	$ 518,891	$ -	$ -	$ -	$ -	$ 518,891
958600 Meter expenses	$ 1,712,041	$ 1,256,088	$ 305,553	$ 143,543	$ 4,919	$ 1,939
958700 Customer installations expenses	$ 117,760	$ 108,168	$ 9,592	$ -	$ -	$ -
958800 Miscellaneous distribution expenses	$ 4,238,510	$ 2,203,299	$ 871,529	$ 844,338	$ 3,955	$ 315,388
958900 Rents	$ 948,564	$ 493,091	$ 195,045	$ 188,960	$ 885	$ 70,583
Total Operation	$ 17,228,746	$ 8,981,925	$ 3,603,720	$ 3,524,767	$ 15,569	$ 1,102,765
Maintenance						
959000 Maintenance Supervision & Engineering	$ 639,052	$ 355,424	$ 131,066	$ 116,384	$ 514	$ 35,663
959200 Maintain equipment	$ 2,762,900	$ 1,491,478	$ 600,801	$ 638,062	$ 11,159	$ 21,400
959300 Maintain overhead lines	$ 14,171,498	$ 8,356,195	$ 3,066,500	$ 2,637,270	$ -	$ 111,533
959400 Maintain underground line	$ 1,404,918	$ 837,891	$ 302,923	$ 253,048	$ -	$ 11,056
959500 Maintain line transformers	$ 851	$ 628	$ 217	$ -	$ -	$ 6
959600 Maintain street lighting & signal systems	$ 556,924	$ -	$ -	$ -	$ -	$ 556,924
959700 Maintain meters	$ 240,829	$ 176,691	$ 42,981	$ 20,192	$ 692	$ 273
959800 Maintain distribution plant	$ 675,747	$ 383,561	$ 141,711	$ 125,298	$ 418	$ 24,759
Total Maintenance	$ 20,452,719	$ 11,601,869	$ 4,286,199	$ 3,790,254	$ 12,784	$ 761,614
Total Distribution Expenses - DE	$ 37,681,466	$ 20,583,794	$ 7,889,919	$ 7,315,021	$ 28,353	$ 1,864,379
Customer Accounts Expenses						
990200 Meter reading expenses	$ 1,534,151	$ 1,301,177	$ 228,911	$ 3,789	$ 65	$ 209
990300 Cust records and collection exp	$ 22,170,713	$ 19,272,386	$ 2,665,192	$ 41,113	$ 1,216	$ 190,805
990500 Miscellaneous cust accounts exp	$ -	$ -	$ -	$ -	$ -	$ -
990400 Uncollectible accounts	$ 1,601,802	$ 1,465,944	$ 107,303	$ -	$ -	$ 28,555
Total Account 990400	$ 1,601,802	$ 1,465,944	$ 107,303	$ -	$ -	$ 28,555
Total Customer Accounts Expenses	$ 25,306,666	$ 22,039,507	$ 3,001,406	$ 44,903	$ 1,282	$ 219,568
Customer Service Expenses						
990700 Supervision	$ 3,870	$ 3,409	$ 413	$ 6	$ 0	$ 42
990800 Customer assistance expenses	$ 2,078,297	$ 1,830,636	$ 221,903	$ 3,380	$ 48	$ 22,330
990900 Informational & instructional adv	$ 176,009	$ 155,035	$ 18,793	$ 286	$ 4	$ 1,891
991000 Miscellaneous customer service & informational exp	$ (13,540)	$ (11,927)	$ (1,446)	$ (22)	$ (0)	$ (145)
Total Customer Service Expenses	$ 2,244,635	$ 1,977,153	$ 239,664	$ 3,651	$ 52	$ 24,117
Sales Expense						
991200 Demonstrating & selling expenses	$ -	$ -	$ -	$ -	$ -	$ -
991300 Advertising expense	$ 186,894	$ 163,784	$ 19,853	$ 302	$ 4	$ 2,951
Total Sales Expense	$ 186,894	$ 163,784	$ 19,853	$ 302	$ 4	$ 2,951

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	Total Delaware Retail	Residential Service	General Service Secondary	General Service Primary	General Service Transmission	Street Lighting Service
Administrative & General Expense						
Operation						
992000 Administrative & General salaries	$ 1,701,666	$ 1,012,482	$ 337,191	$ 285,919	$ 1,162	$ 64,911
992100 Office supplies & expenses	$ 307,319	$ 182,853	$ 60,896	$ 51,637	$ 210	$ 11,723
992300 Outside services employed	$ 25,359,056	$ 15,088,505	$ 5,024,993	$ 4,260,905	$ 17,313	$ 967,341
992300 Outside services employed-Hackett	$ -	$ -	$ -	$ -	$ -	$ -
992400 Property insurance	$ 127,496	$ 78,533	$ 24,500	$ 14,602	$ 104	$ 9,756
992500 Injuries & damages	$ 719,379	$ 428,027	$ 142,548	$ 120,872	$ 491	$ 27,441
992600 Employee pensions & benefits	$ 8,140,986	$ 4,843,844	$ 1,613,167	$ 1,367,873	$ 5,558	$ 310,544
992800 Regulatory commission expenses						
Regulatory commission exp - DE Retail	$ 569,329	$ 350,688	$ 109,405	$ 65,205	$ 467	$ 43,565
Regulatory tax assessment - DE Retail	$ 633,093	$ 398,070	$ 118,540	$ 80,441	$ 1,600	$ 34,443
Regulatory tax assessment - Other DE Ret	$ -	$ -	$ -	$ -	$ -	$ -
Total Acct 992800 Regulatory comm Exp	$ 1,202,422	$ 748,758	$ 227,945	$ 145,646	$ 2,066	$ 78,008
992900 Duplicate charges-Credit	$ (6,776,689)	$ (4,032,094)	$ (1,342,827)	$ (1,138,640)	$ (4,627)	$ (258,502)
993010 General ad expenses	$ -	$ -	$ -	$ -	$ -	$ -
993020 Miscellaneous general expenses	$ 143,527	$ 85,398	$ 28,440	$ 24,116	$ 98	$ 5,475
993020 DE Universal Service Program	$ 4,162,482	$ 1,563,169	$ 968,179	$ 1,242,732	$ 388,123	$ 278
993100 Rents	$ 2,257	$ 1,343	$ 447	$ 379	$ 2	$ 86
Total Operation	$ 35,089,901	$ 20,000,817	$ 7,085,481	$ 6,376,041	$ 410,501	$ 1,217,062
Maintenance						
993500 Maintenance of general plant	$ 2,691,702	$ 1,658,879	$ 516,908	$ 304,202	$ 2,221	$ 209,492
Total Maintenance	$ 2,691,702	$ 1,658,879	$ 516,908	$ 304,202	$ 2,221	$ 209,492
Total Administrative & General Exp	$ 37,781,603	$ 21,659,696	$ 7,602,389	$ 6,680,243	$ 412,721	$ 1,426,554

CCOSS Under Recommended Cost Allocation Factors

	Total Delaware Retail	Residential Service	General Service Secondary	General Service Primary	General Service Transmission	Street Lighting Service
Depreciation & Amortization						
Acct 403 Depreciation						
Distribution						
DE	$ 23,222,015	$ 14,311,582	$ 4,459,505	$ 2,624,429	$ 19,157	$ 1,807,343
General	$ 2,261,435	$ 1,393,708	$ 434,281	$ 255,575	$ 1,866	$ 176,005
Common	$ 1,957,500	$ 1,206,395	$ 375,914	$ 221,226	$ 1,615	$ 152,350
A/C 403 Total	$ 27,440,950	$ 16,911,685	$ 5,269,700	$ 3,101,230	$ 22,637	$ 2,135,697
Acct 405 Amortization of Intangible						
Electric						
Lease Vehicles	$ 42,607	$ 25,351	$ 8,443	$ 7,159	$ 29	$ 1,625
DE IRP Recovery	$ 358,741	$ 220,973	$ 68,937	$ 41,086	$ 294	$ 27,451
DE RFP Recovery	$ 435,538	$ 268,277	$ 83,695	$ 49,882	$ 357	$ 33,327
Intangible - Software	$ 15,253	$ 9,075	$ 3,022	$ 2,563	$ 10	$ 582
A/C 405 Total	$ 852,138	$ 523,676	$ 164,097	$ 100,689	$ 691	$ 62,985
Total Depreciation and Amortization	$ 28,293,088	$ 17,435,361	$ 5,433,797	$ 3,201,920	$ 23,328	$ 2,198,683
Other Taxes						
Payroll Taxes - FICA	$ 1,442,248	$ 858,130	$ 285,787	$ 242,331	$ 985	$ 55,016
Payroll Taxes - FUTA/SUTA	$ 90,788	$ 54,018	$ 17,990	$ 15,254	$ 62	$ 3,463
Property Taxes - Delaware	$ 6,385,636	$ 3,933,342	$ 1,227,093	$ 731,339	$ 5,234	$ 488,629
Franchise Taxes - Delaware	$ (133,928)	$ (82,495)	$ (25,736)	$ (15,339)	$ (110)	$ (10,248)
Local Taxes - Delaware	$ 188,862	$ 118,751	$ 35,362	$ 23,997	$ 477	$ 10,275
Total Other Taxes	$ 7,973,607	$ 4,881,746	$ 1,540,496	$ 997,582	$ 6,648	$ 547,134
Net ITC Adjustment						
Distribution - Delaware	$ (186,300)	$ (114,816)	$ (35,777)	$ (21,055)	$ (154)	$ (14,500)
General	$ (13,362)	$ (8,235)	$ (2,566)	$ (1,510)	$ (11)	$ (1,040)
Common	$ (51,227)	$ (31,571)	$ (9,838)	$ (5,789)	$ (42)	$ (3,987)
Total Net ITC Adjustment	$ (250,890)	$ (154,622)	$ (48,180)	$ (28,354)	$ (207)	$ (19,526)
IOCD						
Delaware	$ 14,967	$ 10,080	$ 2,446	$ 1,439	$ 11	$ 991
Total Interest on Customer Deposits	$ 14,967	$ 10,080	$ 2,446	$ 1,439	$ 11	$ 991
AFUDC						
Distribution - Delaware	$ 515,380	$ 317,625	$ 98,972	$ 58,245	$ 425	$ 40,111
General	$ 449,929	$ 277,289	$ 86,403	$ 50,849	$ 371	$ 35,017
Common	$ -	$ -	$ -	$ -	$ -	$ -
Total AFUDC	$ 965,309	$ 594,914	$ 185,376	$ 109,094	$ 796	$ 75,129

CCOSS Under Recommended Cost Allocation Factors

	Total Delaware Retail	Residential Service	General Service Secondary	General Service Primary	General Service Transmission	Street Lighting Service
FEDERAL & STATE TAX CALCULATION						
OPERATING REVENUES	$ 176,798,863	$ 105,822,844	$ 41,405,174	$ 20,001,445	$ 599,151	$ 8,970,248
OPERATING EXPENSES						
Operation & Maintenance Expense	$ 103,201,264	$ 66,423,934	$ 18,753,231	$ 14,044,120	$ 442,411	$ 3,537,568
Depreciation and Amortization	$ 28,293,088	$ 17,435,361	$ 5,433,797	$ 3,201,920	$ 23,328	$ 2,198,683
Taxes Other than Income Tax	$ 7,973,607	$ 4,881,746	$ 1,540,496	$ 997,582	$ 6,648	$ 547,134
OPERATING INC BEFORE FED TAX	$ 37,330,904	$ 17,081,804	$ 15,677,650	$ 1,757,824	$ 126,764	$ 2,686,863
Less: Interest Expense	$ 16,862,023	$ 10,386,452	$ 3,240,283	$ 1,931,185	$ 13,820	$ 1,290,282
Schedule M						
Labor	$ 138,162	$ 82,206	$ 27,377	$ 23,214	$ 94	$ 5,270
Plant	$ -	$ -	$ -	$ -	$ -	$ -
Timing Labor	$ 383,619	$ 228,252	$ 76,016	$ 64,457	$ 262	$ 14,633
Timing Plant	$ (64,403,063)	$ (39,670,171)	$ (12,375,984)	$ (7,375,998)	$ (52,786)	$ (4,928,123)
Total Schedule M	$ (63,881,281)	$ (39,359,714)	$ (12,272,592)	$ (7,288,327)	$ (52,429)	$ (4,908,220)
TAXABLE INCOME	$ (43,412,401)	$ (32,664,363)	$ 164,776	$ (7,461,689)	$ 60,514	$ (3,511,639)
State Income Taxes	$ (3,776,879)	$ (2,841,800)	$ 14,335	$ (649,167)	$ 5,265	$ (305,513)
State Income Taxes-Prior Year						
Total State Income Taxes	$ (3,776,879)	$ (2,841,800)	$ 14,335	$ (649,167)	$ 5,265	$ (305,513)
Federal Income Taxes	$ (13,872,433)	$ (10,437,897)	$ 52,654	$ (2,384,383)	$ 19,337	$ (1,122,144)
Federal Income Taxes-Prior Year						
Total Federal Income Taxes	$ (13,872,433)	$ (10,437,897)	$ 52,654	$ (2,384,383)	$ 19,337	$ (1,122,144)
Deferred State Income Taxes						
Timing Labor	$ (33,375)	$ (19,858)	$ (6,613)	$ (5,608)	$ (23)	$ (1,273)
Timing Plant	$ 5,603,066	$ 3,451,305	$ 1,076,711	$ 641,712	$ 4,592	$ 428,747
Total Deferred State Income Taxes-Current Year	$ 5,569,692	$ 3,431,447	$ 1,070,097	$ 636,104	$ 4,570	$ 427,474
State Deferred Income Taxes-Prior Year						
Total State Deferred Income Tax	$ 5,569,692	$ 3,431,447	$ 1,070,097	$ 636,104	$ 4,570	$ 427,474
Deferred Federal Income Taxes						
Timing Labor	$ (122,586)	$ (72,938)	$ (24,291)	$ (20,597)	$ (84)	$ (4,676)
Timing Plant	$ 20,579,999	$ 12,676,603	$ 3,954,746	$ 2,357,000	$ 16,868	$ 1,574,782
Total Deferred Federal Income Taxes-Current Year	$ 20,457,413	$ 12,603,665	$ 3,930,455	$ 2,336,403	$ 16,784	$ 1,570,106
Federal Deferred Income Taxes-Prior Year						
Total Federal Deferred Income Tax	$ 20,457,413	$ 12,603,665	$ 3,930,455	$ 2,336,403	$ 16,784	$ 1,570,106
Total Income Taxes	$ 8,377,793	$ 2,755,416	$ 5,067,542	$ (61,042)	$ 45,956	$ 569,922
Total Expenses	$ 146,644,520	$ 90,757,001	$ 30,563,956	$ 18,046,570	$ 517,350	$ 6,759,644
Net Operating Income	$ 30,154,343	$ 15,065,844	$ 10,841,219	$ 1,954,875	$ 81,801	$ 2,210,604

Source: Company's Class Cost of Service Study.

CCOSS Under Company's Recommended Cost Allocation Factors

	Total Delaware Retail	Residential Service	General Service Secondary	General Service Primary	General Service Transmission	Street Lighting Service
RATE BASE						
Total System Electric Distribution	$ 1,106,124,352	$ 678,772,160	$ 213,254,851	$ 131,844,641	$ 1,054,022	$ 81,198,677
Less: Depreciation Reserve	$ 408,440,153	$ 249,970,906	$ 78,919,227	$ 49,936,403	$ 414,041	$ 29,199,577
Total Net Plant	$ 697,684,198	$ 428,801,254	$ 134,335,624	$ 81,908,238	$ 639,981	$ 51,999,100
ADD:						
CWIP	$ 70,154,772	$ 42,408,649	$ 13,700,297	$ 9,701,738	$ 94,020	$ 4,250,068
Working Capital	$ 10,887,807	$ 6,845,141	$ 2,094,932	$ 1,504,384	$ 62,480	$ 380,871
Materials & Supplies	$ 18,164,174	$ 11,159,422	$ 3,497,851	$ 2,127,707	$ 16,510	$ 1,362,684
Miscellaneous Rate Base Items	$ 57,392,849	$ 34,019,624	$ 11,404,173	$ 9,569,333	$ 110,909	$ 2,288,811
DEDUCT:						
Accumulated ITC	$ 1,853,616	$ 1,137,539	$ 357,294	$ 219,814	$ 1,740	$ 137,229
Customer Advances	$ 1,651,163	$ 1,017,601	$ 317,086	$ 186,606	$ 1,362	$ 128,508
Customer Deposits	$ 13,702,572	$ 9,228,734	$ 2,239,072	$ 1,317,699	$ 9,619	$ 907,448
Deferred FIT	$ (135,140,550)	$ (82,750,822)	$ (26,129,701)	$ (16,165,972)	$ (129,048)	$ (9,965,008)
Deferred SIT	$ (27,021,001)	$ (16,534,815)	$ (5,229,218)	$ (3,235,918)	$ (25,820)	$ (1,995,230)
TOTAL RATE BASE	$ 674,914,898	$ 412,564,581	$ 130,760,506	$ 83,685,390	$ 756,312	$ 47,148,109
DEVELOPMENT OF RETURN						
Revenue - Retail Sales	$ 172,900,083	$ 103,098,643	$ 40,836,144	$ 19,723,846	$ 476,853	$ 8,764,597
Interdepartmental	$ 58,423	$ 36,388	$ 11,023	$ 7,768	$ 207	$ 3,036
Other Operating Revenue	$ 3,840,358	$ 2,687,467	$ 558,091	$ 270,176	$ 122,151	$ 202,473
Total Electric Operating Revenue	$ 176,798,863	$ 105,822,498	$ 41,405,259	$ 20,001,790	$ 599,210	$ 8,970,106
LESS:						
Operating & Maintenance Expense	$ 103,201,264	$ 65,521,720	$ 18,965,051	$ 14,661,019	$ 628,432	$ 3,425,042
Depreciation & Amortization Expense	$ 28,293,088	$ 17,318,033	$ 5,466,060	$ 3,451,869	$ 28,523	$ 2,028,603
Other Taxes	$ 7,973,607	$ 4,856,949	$ 1,546,844	$ 1,032,949	$ 9,712	$ 527,152
Net ITC Adjustment	$ (250,890)	$ (152,859)	$ (48,665)	$ (32,121)	$ (284)	$ (16,961)
Interest on Customer Deposits	$ 14,967	$ 10,080	$ 2,446	$ 1,439	$ 11	$ 991
Income Taxes	$ 8,377,793	$ 3,195,405	$ 4,961,522	$ (459,502)	$ (33,844)	$ 714,211
Total Operating Expenses	$ 147,609,829	$ 90,749,329	$ 30,893,257	$ 18,655,654	$ 632,550	$ 6,679,039
PLUS: AFUDC	$ 965,309	$ 582,635	$ 188,755	$ 135,334	$ 1,331	$ 57,255
OPERATING INCOME	$ 30,154,343	$ 15,655,804	$ 10,700,756	$ 1,481,471	$ (32,009)	$ 2,348,321
RATE OF RETURN	4.47%	3.79%	8.18%	1.77%	-4.23%	4.98%
RELATIVE RATE OF RETURN	1.00	0.85	1.83	0.40	(0.95)	1.11

CCOSS Under Company's Recommended Cost Allocation Factors

	Total Delaware Retail	Residential Service	General Service Secondary	General Service Primary	General Service Transmission	Street Lighting Service
ELECTRIC PLANT IN SERVICE						
DISTRIBUTION PLANT						
Distribution - Delaware						
3601 Land and Land Rights	$ 3,380,182	$ 1,824,701	$ 735,031	$ 780,616	$ 13,652	$ 26,181
3601 Land and Land Rights	$ 1,657	$ -	$ -	$ -	$ 1,657	$ -
3602 Land and Land Rights	$ 3,536,923	$ 2,097,547	$ 763,969	$ 647,572	$ -	$ 27,835
3610 Structures and Improvements	$ 15,377,345	$ 8,438,206	$ 3,399,100	$ 3,418,966	$ -	$ 121,074
3610 Structures and Improvements DA GSP	$ 72,487	$ -	$ -	$ 72,487	$ -	$ -
3610 Structures and Improvements DA GST	$ 5,670	$ -	$ -	$ -	$ 5,670	$ -
3620 Station Equipment	$ 138,910,960	$ 76,226,375	$ 30,705,703	$ 30,885,166	$ -	$ 1,093,717
3620 Station Equipment DA GSP	$ 1,724,856	$ -	$ -	$ 1,724,856	$ -	$ -
3620 Station Equipment DA GST	$ 570,326	$ -	$ -	$ -	$ 570,326	$ -
Total Acct 3620	$ 141,206,142	$ 76,226,375	$ 30,705,703	$ 32,610,022	$ 570,326	$ 1,093,717
3640 Poles, Towers and Fixtures						
Demand Primary	$ 52,213,852	$ 28,651,970	$ 11,541,659	$ 11,609,116	$ -	$ 411,106
Demand Secondary	$ 10,168,289	$ 8,131,533	$ 1,956,901	$ -	$ -	$ 79,855
Total Acct 3640	$ 62,382,140	$ 36,783,502	$ 13,498,561	$ 11,609,116	$ -	$ 490,961
3650 Overhead Conductors and Devices						
Demand Primary	$ 98,559,522	$ 54,083,818	$ 21,786,181	$ 21,913,513	$ -	$ 776,009
Demand Secondary	$ 19,193,790	$ 15,349,183	$ 3,693,871	$ -	$ -	$ 150,735
Total Acct 3650	$ 117,753,312	$ 69,433,001	$ 25,480,053	$ 21,913,513	$ -	$ 926,744
3660 Underground Conduit						
Demand Primary	$ 13,561,631	$ 7,441,846	$ 2,997,743	$ 3,015,264	$ -	$ 106,778
Demand Secondary	$ 3,179,057	$ 2,542,277	$ 611,814	$ -	$ -	$ 24,966
Total Acct 3660	$ 16,740,688	$ 9,984,123	$ 3,609,557	$ 3,015,264	$ -	$ 131,744
3670 Underground Conductors and Devices						
Demand Primary	$ 134,071,746	$ 73,570,892	$ 29,636,014	$ 29,809,225	$ -	$ 1,055,615
Demand Secondary	$ 31,428,496	$ 25,133,220	$ 6,048,458	$ -	$ -	$ 246,818
Total Acct 3670	$ 165,500,242	$ 98,704,112	$ 35,684,472	$ 29,809,225	$ -	$ 1,302,433
3680 Line Transformers	$ 206,854,875	$ 152,623,396	$ 52,754,210	$ -	$ -	$ 1,477,270
3691 Services	$ 13,875,916	$ 12,745,640	$ 1,130,276	$ -	$ -	$ -
3692 Services	$ 74,811,527	$ 68,717,681	$ 6,093,846	$ -	$ -	$ -
3700 Metering Equip/Transformers	$ 15,119,144	$ 3,099,383	$ 5,585,454	$ 6,150,431	$ 212,159	$ 71,717
3701 Meters AMI	$ 58,718,914	$ 51,073,994	$ 7,592,635	$ 40,378	$ -	$ 11,907
3712 Installations on Customer Premises	$ 22,434,167	$ -	$ -	$ -	$ -	$ 22,434,167
3713 Installations on Customer Premises	$ 8,496,920	$ 8,489,619	$ 2,980	$ 3,427	$ -	$ 894
3730 Street Lighting and Signal Systems	$ 47,685,013	$ -	$ -	$ -	$ -	$ 47,685,013
Total Distribution - Delaware	$ 973,953,266	$ 600,241,281	$ 187,035,846	$ 110,071,019	$ 803,464	$ 75,801,657

CCOSS Under Company's Recommended Cost Allocation Factors

	Total Delaware Retail	Residential Service	General Service Secondary	General Service Primary	General Service Transmission	Street Lighting Service
ELECTRIC PLANT IN SERVICE						
General Plant						
3891 Land and Land Rights	$ 773,588	$ 455,645	$ 154,367	$ 132,543	$ 1,557	$ 29,475
3903 Structures and Improvements	$ 12,666,366	$ 7,460,521	$ 2,527,538	$ 2,170,196	$ 25,499	$ 482,612
3911 Office Furniture and Equipment	$ 1,472,599	$ 867,364	$ 293,853	$ 252,308	$ 2,964	$ 56,109
3912 Office Furniture and Equipment	$ -	$ -	$ -	$ -	$ -	$ -
3913 Office Furniture and Equipment	$ 138,705	$ 81,697	$ 27,678	$ 23,765	$ 279	$ 5,285
3914 Office Furniture and Equipment	$ -	$ -	$ -	$ -	$ -	$ -
3920 Transportation Equipment	$ 194,304	$ 114,446	$ 38,773	$ 33,291	$ 391	$ 7,403
3930 Stores Equipment	$ 274,401	$ 161,623	$ 54,756	$ 47,015	$ 552	$ 10,455
3932 Stores Equipment	$ -	$ -	$ -	$ -	$ -	$ -
3940 Tools, Shop and Garage Equipment	$ 5,948,457	$ 3,503,656	$ 1,186,998	$ 1,019,181	$ 11,975	$ 226,647
3942 Tools, Shop and Garage Equipment	$ -	$ -	$ -	$ -	$ -	$ -
3950 Laboratory Equipment	$ 292,955	$ 172,551	$ 58,458	$ 50,194	$ 590	$ 11,162
3952 Laboratory Equipment	$ -	$ -	$ -	$ -	$ -	$ -
3970 Communication Equipment	$ 24,404,457	$ 14,374,286	$ 4,869,840	$ 4,181,346	$ 49,128	$ 929,856
3971 Communication Equipment	$ 1,533,863	$ 903,449	$ 306,078	$ 262,805	$ 3,088	$ 58,443
3973 Communication Equipment	$ 4,572,551	$ 2,693,244	$ 912,440	$ 783,440	$ 9,205	$ 174,223
3980 Miscellaneous Equipment	$ 380,658	$ 224,209	$ 75,959	$ 65,220	$ 766	$ 14,504
399 Other Tangible Property	$ 32,395	$ 19,081	$ 6,464	$ 5,550	$ 65	$ 1,234
3991 Other Tangible Property	$ 80,465	$ 47,394	$ 16,057	$ 13,787	$ 162	$ 3,066
Total General Plant	$ 52,765,765	$ 31,079,167	$ 10,529,259	$ 9,040,641	$ 106,222	$ 2,010,475
Intangible Plant						
3020 010 Franchises and Consents	$ 313	$ 193	$ 60	$ 35	$ 0	$ 24
3020 020 Franchises and Consents	$ 960	$ 592	$ 184	$ 109	$ 1	$ 75
3020 030 Franchises and Consents	$ -	$ -	$ -	$ -	$ -	$ -
3030 000 Miscellaneous Intangible Plant	$ 2,935,378	$ 1,809,055	$ 563,704	$ 331,741	$ 2,422	$ 228,457
3030 010 Miscellaneous Intangible Plant	$ 5,677,924	$ 3,499,269	$ 1,090,376	$ 641,689	$ 4,684	$ 441,906
3030 020 Miscellaneous Intangible Plant	$ 228,795	$ 141,005	$ 43,937	$ 25,857	$ 189	$ 17,807
Total Intangible Plant	$ 8,843,369	$ 5,450,113	$ 1,698,261	$ 999,431	$ 7,295	$ 688,269

CCOSS Under Company's Recommended Cost Allocation Factors

	Total Delaware Retail	Residential Service	General Service Secondary	General Service Primary	General Service Transmission	Street Lighting Service
ELECTRIC PLANT IN SERVICE						
Common Plant						
C3891 Land and Land Rights	$ 894,237	$ 526,708	$ 178,443	$ 153,214	$ 1,800	$ 34,072
C3903 Structures and Improvements	$ 22,522,987	$ 13,266,096	$ 4,494,398	$ 3,858,984	$ 45,341	$ 858,168
C3911 Office Furniture and Equipment	$ 3,053,187	$ 1,798,335	$ 609,255	$ 523,119	$ 6,146	$ 116,332
C3912 Office Furniture and Equipment	$ -	$ -	$ -	$ -	$ -	$ -
C3913 Office Furniture and Equipment	$ 1,021,648	$ 601,753	$ 203,867	$ 175,044	$ 2,057	$ 38,927
C3914 Office Furniture and Equipment	$ -	$ -	$ -	$ -	$ -	$ -
C3930 Stores Equipment	$ 105,989	$ 62,428	$ 21,150	$ 18,160	$ 213	$ 4,038
C3932 Stores Equipment	$ -	$ -	$ -	$ -	$ -	$ -
C3940 Tools, Shop and Garage Equipment	$ 1,988,850	$ 1,171,438	$ 396,869	$ 340,760	$ 4,004	$ 75,779
C3942 Tools, Shop and Garage Equipment	$ -	$ -	$ -	$ -	$ -	$ -
C3970 Communication Equipment	$ 9,520,504	$ 5,607,600	$ 1,899,790	$ 1,631,199	$ 19,166	$ 362,749
C3971 Communication Equipment	$ 116,841	$ 68,820	$ 23,315	$ 20,019	$ 235	$ 4,452
C3980 Miscellaneous Equipment	$ 1,059,211	$ 623,878	$ 211,363	$ 181,480	$ 2,132	$ 40,358
C3982 Miscellaneous Equipment	$ -	$ -	$ -	$ -	$ -	$ -
Total Common - General	$ 40,283,455	$ 23,727,056	$ 8,038,449	$ 6,901,980	$ 81,094	$ 1,534,876
Misc. Intangible						
3010 Organization	$ 400,455	$ 246,798	$ 76,902	$ 45,257	$ 330	$ 31,167
3031 070 Software 10 Year	$ 9,492,184	$ 5,590,920	$ 1,894,138	$ 1,626,347	$ 19,109	$ 361,670
3030 070 Miscellaneous Intangible Plant	$ -	$ -	$ -	$ -	$ -	$ -
C3030 Miscellaneous Intangible Plant	$ 1,638,819	$ 1,009,994	$ 314,715	$ 185,211	$ 1,352	$ 127,547
Total Common - Intangible	$ 11,531,457	$ 6,847,711	$ 2,285,756	$ 1,856,814	$ 20,791	$ 520,384
Total Electric Common @ 84%	$ 43,524,526	$ 25,682,804	$ 8,672,333	$ 7,357,387	$ 85,584	$ 1,726,418
Total pre-Service Co Electric Plant In Service	$ 1,079,086,926	$ 662,453,365	$ 207,935,698	$ 127,468,477	$ 1,002,565	$ 80,226,820
Service Company Assets	$ 25,499,805	$ 15,019,449	$ 5,088,414	$ 4,369,018	$ 51,333	$ 971,591
AMI IT Hardware & Software	$ 1,537,620	$ 1,299,346	$ 230,739	$ 7,146	$ 123	$ 266
Total System Electric Distribution	$ 1,106,124,352	$ 678,772,160	$ 213,254,851	$ 131,844,641	$ 1,054,022	$ 81,198,677

CCOSS Under Company's Recommended Cost Allocation Factors

	Total Delaware Retail	Residential Service	General Service Secondary	General Service Primary	General Service Transmission	Street Lighting Service
DEPRECIATION RESERVE						
Distribution - Delaware	$ 332,955,907	$ 205,198,634	$ 63,940,121	$ 37,628,906	$ 274,672	$ 25,913,573
General	$ 17,296,068	$ 10,187,427	$ 3,451,381	$ 2,963,428	$ 34,819	$ 659,013
Intangible	$ 8,767,140	$ 5,403,133	$ 1,683,622	$ 990,815	$ 7,232	$ 682,336
Common Intangible (Electric @ 84%)	$ 9,350,042	$ 5,552,324	$ 1,853,358	$ 1,505,559	$ 16,858	$ 421,943
Common (Electric @ 84%)	$ 24,765,656	$ 14,587,033	$ 4,941,917	$ 4,243,232	$ 49,856	$ 943,618
Service Company Assets Reserve	$ 15,198,052	$ 8,951,690	$ 3,032,728	$ 2,603,963	$ 30,595	$ 579,074
AMI IT Hardware & Software	$ 107,290	$ 90,664	$ 16,100	$ 499	$ 9	$ 19
Total Depreciation Reserve	$ 408,440,153	$ 249,970,906	$ 78,919,227	$ 49,936,403	$ 414,041	$ 29,199,577
Total Net Plant	$ 697,684,198	$ 428,801,254	$ 134,335,624	$ 81,908,238	$ 639,981	$ 51,999,100
CWIP						
Distribution - Delaware	$ 30,778,211	$ 18,968,418	$ 5,910,580	$ 3,478,390	$ 25,391	$ 2,395,433
General	$ 22,426,048	$ 13,208,998	$ 4,475,054	$ 3,842,375	$ 45,146	$ 854,475
Other	$ 10,035,417	$ 6,158,224	$ 1,934,775	$ 1,196,173	$ 9,563	$ 736,683
Common (Electric @ 84%)	$ 716,062	$ 421,762	$ 142,888	$ 122,687	$ 1,441	$ 27,283
Service Company Assets	$ 6,199,034	$ 3,651,246	$ 1,237,000	$ 1,062,114	$ 12,479	$ 236,195
Total CWIP	$ 70,154,772	$ 42,408,649	$ 13,700,297	$ 9,701,738	$ 94,020	$ 4,250,068
MATERIALS & SUPPLIES						
Distribution	$ 16,880,097	$ 10,403,098	$ 3,241,617	$ 1,907,699	$ 13,925	$ 1,313,758
Labor Stock	$ 1,284,077	$ 756,324	$ 256,234	$ 220,008	$ 2,585	$ 48,926
Total Materials & Supplies	$ 18,164,174	$ 11,159,422	$ 3,497,851	$ 2,127,707	$ 16,510	$ 1,362,684
Cash Working Capital						
O&M - Distribution	$ 10,172,262	$ 6,458,294	$ 1,869,332	$ 1,445,096	$ 61,943	$ 337,597
Payroll Taxes	$ 147,298	$ 86,759	$ 29,393	$ 25,237	$ 297	$ 5,612
Franchise Taxes - Delaware	$ 31,423	$ 19,283	$ 6,058	$ 3,746	$ 30	$ 2,307
Utility Tax	$ 257,333	$ 160,279	$ 48,554	$ 34,217	$ 911	$ 13,372
Local Taxes - Delaware	$ 47,966	$ 29,875	$ 9,050	$ 6,378	$ 170	$ 2,492
Propery Tax - Delaware	$ 2,506,318	$ 1,538,000	$ 483,205	$ 298,741	$ 2,388	$ 183,985
FIT	$ 260,491	$ 188,622	$ 816	$ 52,450	$ 863	$ 17,739
SIT	$ (723,161)	$ (523,644)	$ (2,266)	$ (145,608)	$ (2,396)	$ (49,247)
Interest Expense	$ (1,806,777)	$ (1,108,727)	$ (348,337)	$ (215,359)	$ (1,722)	$ (132,632)
IOCD	$ (5,345)	$ (3,600)	$ (873)	$ (514)	$ (4)	$ (354)
Total Cash Working Capital	$ 10,887,807	$ 6,845,141	$ 2,094,932	$ 1,504,384	$ 62,480	$ 380,871

CCOSS Under Company's Recommended Cost Allocation Factors

	Total Delaware Retail	Residential Service	General Service Secondary	General Service Primary	General Service Transmission	Street Lighting Service
MISC RATE BASE ITEMS						
Prepaid Insurance	$ 41,431	$ 24,403	$ 8,267	$ 7,099	$ 83	$ 1,579
OPEB Liability	$ (8,176,221)	$ (4,815,815)	$ (1,631,542)	$ (1,400,876)	$ (16,459)	$ (311,529)
IRP Regulatory Asset (DE)	$ 1,552,358	$ 952,603	$ 299,286	$ 185,034	$ 1,479	$ 113,956
RFP Regulatory Asset (DE)	$ 1,884,676	$ 1,156,530	$ 363,355	$ 224,644	$ 1,796	$ 138,351
AMI Regulatory Asset (DE)	$ 509,235	$ 430,322	$ 76,417	$ 2,367	$ 41	$ 88
Prepaid Pension	$ 61,581,370	$ 36,271,581	$ 12,288,388	$ 10,551,066	$ 123,969	$ 2,346,366
Total Misc Rate Base Items	$ 57,392,849	$ 34,019,624	$ 11,404,173	$ 9,569,333	$ 110,909	$ 2,288,811
ACCUMULATED ITC						
Distribution - Delaware	$ 1,676,524	$ 1,033,231	$ 321,956	$ 189,472	$ 1,383	$ 130,482
General	$ 55,103	$ 32,456	$ 10,996	$ 9,441	$ 111	$ 2,100
Common	$ 121,988	$ 71,851	$ 24,342	$ 20,901	$ 246	$ 4,648
Total Accumulated ITC	$ 1,853,616	$ 1,137,539	$ 357,294	$ 219,814	$ 1,740	$ 137,229
CUSTOMER ADVANCES						
Delaware	$ 1,651,163	$ 1,017,601	$ 317,086	$ 186,606	$ 1,362	$ 128,508
Total Customer Advances	$ 1,651,163	$ 1,017,601	$ 317,086	$ 186,606	$ 1,362	$ 128,508
CUSTOMER DEPOSITS						
Delaware	$ 9,228,734	$ 9,228,734	$ -	$ -	$ -	$ -
Delaware	$ 4,473,838	$ -	$ 2,239,072	$ 1,317,699	$ 9,619	$ 907,448
Total Customer Deposits	$ 13,702,572	$ 9,228,734	$ 2,239,072	$ 1,317,699	$ 9,619	$ 907,448
DEFERRED FIT						
Labor	$ 294,973	$ 173,740	$ 58,861	$ 50,539	$ 594	$ 11,239
Plant	$ (136,050,106)	$ (83,487,019)	$ (26,229,732)	$ (16,216,511)	$ (129,642)	$ (9,987,203)
Uncollectible Expense	$ 614,584	$ 562,458	$ 41,170	$ -	$ -	$ 10,956
Total Deferred FIT	$ (135,140,550)	$ (82,750,822)	$ (26,129,701)	$ (16,165,972)	$ (129,048)	$ (9,965,008)
DEFERRED SIT						
Labor	$ 77,197	$ 45,469	$ 15,404	$ 13,227	$ 155	$ 2,941
Plant	$ (27,259,041)	$ (16,727,485)	$ (5,255,397)	$ (3,249,145)	$ (25,975)	$ (2,001,039)
Uncollectible Expense	$ 160,842	$ 147,200	$ 10,775	$ -	$ -	$ 2,867
Total Deferred SIT	$ (27,021,001)	$ (16,534,815)	$ (5,229,218)	$ (3,235,918)	$ (25,820)	$ (1,995,230)
Total Rate Base	$ 674,914,898	$ 412,564,581	$ 130,760,506	$ 83,685,390	$ 756,312	$ 47,148,109

CCOSS Under Company's Recommended Cost Allocation Factors

	Total Delaware Retail	Residential Service	General Service Secondary	General Service Primary	General Service Transmission	Street Lighting Service
ELECTRIC SALES REVENUES						
Revenue - Retail Sales DE	$ 172,900,083	$ 103,098,643	$ 40,836,144	$ 19,723,846	$ 476,853	$ 8,764,597
INTERDEPARTMENTAL	$ 58,423	$ 36,388	$ 11,023	$ 7,768	$ 207	$ 3,036
REVENUE - OTHER						
Misc Other	$ -	$ -	$ -	$ -	$ -	$ -
Premise Collection Fee	$ 173,200	$ 151,783	$ 18,399	$ 280	$ 4	$ 2,734
Late Payment Revenue DE	$ 833,055	$ 762,399	$ 55,805	$ -	$ -	$ 14,851
Miscellaneous Service Revenue DE	$ 411,589	$ 360,693	$ 43,722	$ 666	$ 9	$ 6,498
Special Facilities Charge (Delaware) GSP	$ 10,192	$ -	$ -	$ 10,192	$ -	$ -
Special Facilities Charge (Delaware) GST	$ 120,246	$ -	$ -	$ -	$ 120,246	$ -
Miscellaneous Service Revenue DE DA GST	$ -	$ -	$ -	$ -	$ -	$ -
Rent from Electric Property DE	$ 2,292,075	$ 1,412,592	$ 440,165	$ 259,038	$ 1,891	$ 178,390
Total Other Revenue	$ 3,840,358	$ 2,687,467	$ 558,091	$ 270,176	$ 122,151	$ 202,473
Total Revenue	$ 176,798,863	$ 105,822,498	$ 41,405,259	$ 20,001,790	$ 599,210	$ 8,970,106

CCOSS Under Company's Recommended Cost Allocation Factors

	Total Delaware Retail	Residential Service	General Service Secondary	General Service Primary	General Service Transmission	Street Lighting Service
Distribution Expenses - DE						
Operation						
958000 Operation Supervision & Engineering	$ 4,534,354	$ 2,383,016	$ 993,479	$ 995,964	$ 3,722	$ 158,173
958100 Load dispatching	$ 2,559,904	$ 1,024,923	$ 666,415	$ 851,163	$ -	$ 17,404
958200 Station expenses	$ 516,665	$ 278,908	$ 112,350	$ 119,318	$ 2,087	$ 4,002
958300 Overhead line expenses	$ 1,081,762	$ 637,859	$ 234,077	$ 201,312	$ -	$ 8,514
958400 Underground line expenses	$ 1,000,294	$ 596,574	$ 215,679	$ 180,169	$ -	$ 7,872
958500 Street lighting	$ 518,891	$ -	$ -	$ -	$ -	$ 518,891
958600 Meter expenses	$ 1,712,041	$ 1,256,088	$ 305,553	$ 143,543	$ 4,919	$ 1,939
958700 Customer installations expenses	$ 117,760	$ 108,168	$ 9,592	$ -	$ -	$ -
958800 Miscellaneous distribution expenses	$ 4,238,510	$ 2,203,299	$ 871,529	$ 844,338	$ 3,955	$ 315,388
958900 Rents	$ 948,564	$ 493,091	$ 195,045	$ 188,960	$ 885	$ 70,583
Total Operation	$ 17,228,746	$ 8,981,925	$ 3,603,720	$ 3,524,767	$ 15,569	$ 1,102,765
Maintenance						
959000 Maintenance Supervision & Engineering	$ 639,052	$ 355,424	$ 131,066	$ 116,384	$ 514	$ 35,663
959200 Maintain equipment	$ 2,762,900	$ 1,491,478	$ 600,801	$ 638,062	$ 11,159	$ 21,400
959300 Maintain overhead lines	$ 14,171,498	$ 8,356,195	$ 3,066,500	$ 2,637,270	$ -	$ 111,533
959400 Maintain underground line	$ 1,404,918	$ 837,891	$ 302,923	$ 253,048	$ -	$ 11,056
959500 Maintain line transformers	$ 851	$ 628	$ 217	$ -	$ -	$ 6
959600 Maintain street lighting & signal systems	$ 556,924	$ -	$ -	$ -	$ -	$ 556,924
959700 Maintain meters	$ 240,829	$ 176,691	$ 42,981	$ 20,192	$ 692	$ 273
959800 Maintain distribution plant	$ 675,747	$ 383,561	$ 141,711	$ 125,298	$ 418	$ 24,759
Total Maintenance	$ 20,452,719	$ 11,601,869	$ 4,286,199	$ 3,790,254	$ 12,784	$ 761,614
Total Distribution Expenses - DE	$ 37,681,466	$ 20,583,794	$ 7,889,919	$ 7,315,021	$ 28,353	$ 1,864,379
Customer Accounts Expenses						
990200 Meter reading expenses	$ 1,534,151	$ 1,301,177	$ 228,911	$ 3,789	$ 65	$ 209
990300 Cust records and collection exp	$ 22,170,713	$ 19,272,386	$ 2,665,192	$ 41,113	$ 1,216	$ 190,805
990500 Miscellaneous cust accounts exp	$ -	$ -	$ -	$ -	$ -	$ -
990400 Uncollectible accounts	$ 1,601,802	$ 1,465,944	$ 107,303	$ -	$ -	$ 28,555
Total Account 990400	$ 1,601,802	$ 1,465,944	$ 107,303	$ -	$ -	$ 28,555
Total Customer Accounts Expenses	$ 25,306,666	$ 22,039,507	$ 3,001,406	$ 44,903	$ 1,282	$ 219,568
Customer Service Expenses						
990700 Supervision	$ 3,870	$ 2,379	$ 650	$ 571	$ 227	$ 42
990800 Customer assistance expenses	$ 2,078,297	$ 1,277,736	$ 349,182	$ 306,712	$ 122,028	$ 22,639
990900 Informational & instructional adv	$ 176,009	$ 108,210	$ 29,572	$ 25,975	$ 10,334	$ 1,917
991000 Miscellaneous customer service & informational exp	$ (13,540)	$ (8,325)	$ (2,275)	$ (1,998)	$ (795)	$ (147)
Total Customer Service Expenses	$ 2,244,635	$ 1,380,001	$ 377,129	$ 331,260	$ 131,794	$ 24,451
Sales Expense						
991200 Demonstrating & selling expenses	$ -	$ -	$ -	$ -	$ -	$ -
991300 Advertising expense	$ 186,894	$ 114,903	$ 31,401	$ 27,582	$ 10,974	$ 2,036
Total Sales Expense	$ 186,894	$ 114,903	$ 31,401	$ 27,582	$ 10,974	$ 2,036

CCOSS Under Company's Recommended Cost Allocation Factors

	Total Delaware Retail	Residential Service	General Service Secondary	General Service Primary	General Service Transmission	Street Lighting Service
Administrative & General Expense						
Operation						
992000 Administrative & General salaries	$ 1,701,666	$ 1,002,285	$ 339,563	$ 291,555	$ 3,426	$ 64,837
992100 Office supplies & expenses	$ 307,319	$ 181,012	$ 61,325	$ 52,655	$ 619	$ 11,709
992300 Outside services employed	$ 25,359,056	$ 14,936,548	$ 5,060,328	$ 4,344,903	$ 51,050	$ 966,228
992300 Outside services employed-Hackett	$ -	$ -	$ -	$ -	$ -	$ -
992400 Property insurance	$ 127,496	$ 78,238	$ 24,580	$ 15,197	$ 121	$ 9,359
992500 Injuries & damages	$ 719,379	$ 423,716	$ 143,550	$ 123,255	$ 1,448	$ 27,410
992600 Employee pensions & benefits	$ 8,140,986	$ 4,795,061	$ 1,624,511	$ 1,394,839	$ 16,389	$ 310,187
992800 Regulatory commission expenses						
Regulatory commission exp - DE Retail	$ 569,329	$ 349,368	$ 109,764	$ 67,861	$ 543	$ 41,793
Regulatory tax assessment - DE Retail	$ 633,093	$ 394,319	$ 119,453	$ 84,182	$ 2,241	$ 32,897
Regulatory tax assessment - Other DE Ret	$ -	$ -	$ -	$ -	$ -	$ -
Total Acct 992800 Regulatory comm Exp	$ 1,202,422	$ 743,688	$ 229,217	$ 152,043	$ 2,784	$ 74,690
992900 Duplicate charges-Credit	$ (6,776,689)	$ (3,991,487)	$ (1,352,269)	$ (1,161,086)	$ (13,642)	$ (258,205)
993010 General ad expenses	$ -	$ -	$ -	$ -	$ -	$ -
993020 Miscellaneous general expenses	$ 143,527	$ 84,538	$ 28,640	$ 24,591	$ 289	$ 5,469
993020 DE Universal Service Program	$ 4,162,482	$ 1,563,169	$ 968,179	$ 1,242,732	$ 388,123	$ 278
993100 Rents	$ 2,257	$ 1,330	$ 450	$ 387	$ 5	$ 86
Total Operation	$ 35,089,901	$ 19,818,097	$ 7,128,074	$ 6,481,071	$ 450,611	$ 1,212,048
Maintenance						
993500 Maintenance of general plant	$ 2,691,702	$ 1,585,419	$ 537,121	$ 461,184	$ 5,419	$ 102,559
Total Maintenance	$ 2,691,702	$ 1,585,419	$ 537,121	$ 461,184	$ 5,419	$ 102,559
Total Administrative & General Exp	$ 37,781,603	$ 21,403,516	$ 7,665,196	$ 6,942,254	$ 456,029	$ 1,314,607

CCOSS Under Company's Recommended Cost Allocation Factors

	Total Delaware Retail	Residential Service	General Service Secondary	General Service Primary	General Service Transmission	Street Lighting Service
Depreciation & Amortization						
Acct 403 Depreciation						
Distribution						
DE	$ 23,222,015	$ 14,311,582	$ 4,459,505	$ 2,624,429	$ 19,157	$ 1,807,343
General	$ 2,261,435	$ 1,331,991	$ 451,263	$ 387,464	$ 4,552	$ 86,165
Common	$ 1,957,500	$ 1,152,973	$ 390,614	$ 335,389	$ 3,941	$ 74,584
A/C 403 Total	$ 27,440,950	$ 16,796,545	$ 5,301,381	$ 3,347,281	$ 27,650	$ 1,968,092
Acct 405 Amortization of Intangible						
Electric						
Lease Vehicles	$ 42,607	$ 25,095	$ 8,502	$ 7,300	$ 86	$ 1,623
DE IRP Recovery	$ 358,741	$ 220,141	$ 69,163	$ 42,760	$ 342	$ 26,335
DE RFP Recovery	$ 435,538	$ 267,267	$ 83,969	$ 51,914	$ 415	$ 31,972
Intangible - Software	$ 15,253	$ 8,984	$ 3,044	$ 2,613	$ 31	$ 581
A/C 405 Total	$ 852,138	$ 521,488	$ 164,678	$ 104,588	$ 873	$ 60,511
Total Depreciation and Amortization	$ 28,293,088	$ 17,318,033	$ 5,466,060	$ 3,451,869	$ 28,523	$ 2,028,603
Other Taxes						
Payroll Taxes - FICA	$ 1,442,248	$ 849,488	$ 287,797	$ 247,108	$ 2,903	$ 54,952
Payroll Taxes - FUTA/SUTA	$ 90,788	$ 53,474	$ 18,116	$ 15,555	$ 183	$ 3,459
Property Taxes - Delaware	$ 6,385,636	$ 3,918,540	$ 1,231,116	$ 761,137	$ 6,085	$ 468,759
Franchise Taxes - Delaware	$ (133,928)	$ (82,185)	$ (25,821)	$ (15,964)	$ (128)	$ (9,831)
Local Taxes - Delaware	$ 188,862	$ 117,632	$ 35,635	$ 25,113	$ 669	$ 9,814
Total Other Taxes	$ 7,973,607	$ 4,856,949	$ 1,546,844	$ 1,032,949	$ 9,712	$ 527,152
Net ITC Adjustment						
Distribution - Delaware	$ (186,300)	$ (114,816)	$ (35,777)	$ (21,055)	$ (154)	$ (14,500)
General	$ (13,362)	$ (7,871)	$ (2,666)	$ (2,289)	$ (27)	$ (509)
Common	$ (51,227)	$ (30,173)	$ (10,222)	$ (8,777)	$ (103)	$ (1,952)
Total Net ITC Adjustment	$ (250,890)	$ (152,859)	$ (48,665)	$ (32,121)	$ (284)	$ (16,961)
IOCD						
Delaware	$ 14,967	$ 10,080	$ 2,446	$ 1,439	$ 11	$ 991
Total Interest on Customer Deposits	$ 14,967	$ 10,080	$ 2,446	$ 1,439	$ 11	$ 991
AFUDC						
Distribution - Delaware	$ 515,380	$ 317,625	$ 98,972	$ 58,245	$ 425	$ 40,111
General	$ 449,929	$ 265,009	$ 89,782	$ 77,089	$ 906	$ 17,143
Common	$ -	$ -	$ -	$ -	$ -	$ -
Total AFUDC	$ 965,309	$ 582,635	$ 188,755	$ 135,334	$ 1,331	$ 57,255

CCOSS Under Company's Recommended Cost Allocation Factors

	Total Delaware Retail	Residential Service	General Service Secondary	General Service Primary	General Service Transmission	Street Lighting Service
FEDERAL & STATE TAX CALCULATION						
OPERATING REVENUES	$ 176,798,863	$ 105,822,498	$ 41,405,259	$ 20,001,790	$ 599,210	$ 8,970,106
OPERATING EXPENSES						
Operation & Maintenance Expense	$ 103,201,264	$ 65,521,720	$ 18,965,051	$ 14,661,019	$ 628,432	$ 3,425,042
Depreciation and Amortization	$ 28,293,088	$ 17,318,033	$ 5,466,060	$ 3,451,869	$ 28,523	$ 2,028,603
Taxes Other than Income Tax	$ 7,973,607	$ 4,856,949	$ 1,546,844	$ 1,032,949	$ 9,712	$ 527,152
OPERATING INC BEFORE FED TAX	$ 37,330,904	$ 18,125,796	$ 15,427,304	$ 855,953	$ (67,457)	$ 2,989,309
Less: Interest Expense	$ 16,862,023	$ 10,347,365	$ 3,250,908	$ 2,009,871	$ 16,068	$ 1,237,812
Schedule M						
Labor	$ 138,162	$ 81,378	$ 27,570	$ 23,672	$ 278	$ 5,264
Plant	$ -	$ -	$ -	$ -	$ -	$ -
Timing Labor	$ 383,619	$ 225,953	$ 76,550	$ 65,728	$ 772	$ 14,617
Timing Plant	$ (64,403,063)	$ (39,520,878)	$ (12,416,566)	$ (7,676,532)	$ (61,369)	$ (4,727,718)
Total Schedule M	$ (63,881,281)	$ (39,213,548)	$ (12,312,446)	$ (7,587,132)	$ (60,319)	$ (4,707,837)
TAXABLE INCOME	$ (43,412,401)	$ (31,435,117)	$ (136,049)	$ (8,741,051)	$ (143,844)	$ (2,956,340)
State Income Taxes	$ (3,776,879)	$ (2,734,855)	$ (11,836)	$ (760,471)	$ (12,514)	$ (257,202)
State Income Taxes-Prior Year						
Total State Income Taxes	$ (3,776,879)	$ (2,734,855)	$ (11,836)	$ (760,471)	$ (12,514)	$ (257,202)
Federal Income Taxes	$ (13,872,433)	$ (10,045,092)	$ (43,475)	$ (2,793,203)	$ (45,965)	$ (944,698)
Federal Income Taxes-Prior Year						
Total Federal Income Taxes	$ (13,872,433)	$ (10,045,092)	$ (43,475)	$ (2,793,203)	$ (45,965)	$ (944,698)
Deferred State Income Taxes						
Timing Labor	$ (33,375)	$ (19,658)	$ (6,660)	$ (5,718)	$ (67)	$ (1,272)
Timing Plant	$ 5,603,066	$ 3,438,316	$ 1,080,241	$ 667,858	$ 5,339	$ 411,311
Total Deferred State Income Taxes-Current Year	$ 5,569,692	$ 3,418,659	$ 1,073,581	$ 662,140	$ 5,272	$ 410,040
State Deferred Income Taxes-Prior Year						
Total State Deferred Income Tax	$ 5,569,692	$ 3,418,659	$ 1,073,581	$ 662,140	$ 5,272	$ 410,040
Deferred Federal Income Taxes						
Timing Labor	$ (122,586)	$ (72,203)	$ (24,462)	$ (21,003)	$ (247)	$ (4,671)
Timing Plant	$ 20,579,999	$ 12,628,897	$ 3,967,714	$ 2,453,036	$ 19,611	$ 1,510,742
Total Deferred Federal Income Taxes-Current Year	$ 20,457,413	$ 12,556,694	$ 3,943,252	$ 2,432,032	$ 19,364	$ 1,506,071
Federal Deferred Income Taxes-Prior Year						
Total Federal Deferred Income Tax	$ 20,457,413	$ 12,556,694	$ 3,943,252	$ 2,432,032	$ 19,364	$ 1,506,071
Total Income Taxes	$ 8,377,793	$ 3,195,405	$ 4,961,522	$ (459,502)	$ (33,844)	$ 714,211
Total Expenses	$ 146,644,520	$ 90,166,694	$ 30,704,503	$ 18,520,320	$ 631,219	$ 6,621,784
Net Operating Income	$ 30,154,343	$ 15,655,804	$ 10,700,756	$ 1,481,471	$ (32,009)	$ 2,348,321

Source: Company's Class Cost of Service Study.

Recommended Revenue Distribution at Limitation of 1.15 Times the System Average

Witness: Dismukes
Docket No. 13-115
Schedule DED-13
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	Total Delaware Retail	Residential Service	Residential Space Heating	General Service-Small	General Service-Large	Primary Service	Transmission Service	Traffic Lights	Street Lighting Service
Cost of Service Study Results									
Operating Income	$ 30,154,343	$ 11,620,205	$ 3,445,639	$ 9,314,127	$ 1,527,092	$ 1,954,875	$ 81,801	$ 14,655	$ 2,195,949
Distribution Rate Base	$ 674,914,898	$ 277,761,997	$ 136,808,538	$ 97,832,710	$ 32,396,337	$ 80,156,565	$ 583,688	$ 190,972	$ 49,184,093
ROR	4.47%	4.18%	2.52%	9.52%	4.71%	2.44%	14.01%	7.67%	4.46%
Unitized ROR	1.00	0.94	0.56	2.13	1.06	0.55	3.14	1.72	1.00
Revenue Requirements Results									
Operating Income	34,970,409	$ 13,476,112	$ 3,995,955	$ 10,801,722	$ 1,770,989	$ 2,267,096	$ 94,866	$ 16,996	$ 2,546,673
Distribution Rate Base	553,669,028	$ 227,863,121	$ 112,231,409	$ 80,257,439	$ 26,576,460	$ 65,756,746	$ 478,830	$ 156,664	$ 40,348,359
ROR	6.32%	5.91%	3.56%	13.46%	6.66%	3.45%	19.81%	10.85%	6.31%
Unitized ROR	1.00	0.94	0.56	2.13	1.06	0.55	3.14	1.72	1.00
Rate Schedule Specific Revenue Increase Allocation									
Revenue Requirement	7,309,999								
Operating Income Deficiency Schedule	$ 4,284,726								
ROR Schedule	7.09%								

Recommended Revenue Distribution at Limitation of 1.15 Times the System Average

	Total Delaware Retail	Residential Service	Residential Space Heating	General Service-Small	General Service-Large	Primary Service	Transmission Service	Traffic Lights	Street Lighting Service
Step One Increase									
System ROR	7.09%	7.09%	7.09%	7.09%	7.09%	7.09%	7.09%	7.09%	7.09%
Incremental Income	$ 4,265,848	$ 8,073,121	$ 6,254,086	$ (2,377,788)	$ 769,809	$ 3,728,225	$ (40,418)	$ (1,115)	$ 1,291,203
Revenue Conversion Factor	1.7136	1.7136	1.7136	1.7136	1.7136	1.7136	1.7136	2.7136	3.7136
Revenue Requirement	$ 7,309,999	$ 13,834,181	$ 10,717,065	$ (4,074,601)	$ 1,319,152	$ 6,388,724	$ (69,260)	$ (3,026)	$ 4,795,023
Percent Increase @ System ROR	4.02%	17.60%	34.68%	-11.59%	17.36%	31.97%	-16.35%	-0.03%	51.51%
Maximum Increase @ 1.15 Times System Average Increase	4.62%	4.62%	4.62%	4.62%	4.62%	4.62%	4.62%	4.62%	4.62%
Required Percentage Increase with Limitation		4.62%	4.62%	0.00%	4.62%	4.62%	0.00%	0.00%	4.62%
Initial Increase	$ 6,762,825	$ 3,630,995	$ 1,427,574	$ -	$ 350,981	$ 923,208	$ -	$ -	$ 430,068
Shortfall In Required Increase	$ 547,174								
Step Two Increase									
Basis to Allocate Step Two Increase	$ 35,578,986	$ -	$ -	$ 35,155,271	$ -	$ -	$ 423,715	$ -	$ -
Allocation of Shortfall to Remaining Customer Classes	$ 547,174	$ -	$ -	$ 540,658	$ -	$ -	$ 6,516	$ -	$ -
Total Required Increase	$ 7,309,999	$ 3,630,995	$ 1,427,574	$ 540,658	$ 350,981	$ 923,208	$ 6,516	$ -	$ 430,068
Proposed Revenue Allocation									
ROR	7.09%	6.85%	4.31%	13.85%	7.44%	4.27%	20.61%	10.85%	6.94%
Incremental Income	$ 4,284,726	$ 2,128,293	$ 836,766	$ 316,904	$ 205,726	$ 541,135	$ 3,820	$ -	$ 252,082
Revenue Conversion Factor	1.7061	1.7061	1.7061	1.7061	1.7061	1.7061	1.7061	1.7061	1.7061
Revenue Requirement	$ 7,309,999	$ 3,630,995	$ 1,427,574	$ 540,658	$ 350,981	$ 923,208	$ 6,516	$ -	$ 430,068
Final Unitized ROR	1.00	0.97	0.61	1.95	1.05	0.60	2.91	1.53	0.98

Recommended Revenue Distribution at Limitation of 1.15 Times the System Average

	Total	Residential			General Service Secondary "Small" (GSS-S)			
		R	RSH	RTOU-ND	SGS-S	GS-SH	GS-WH	MGS
Annualized Current Distribution Revenue	$ 181,967,151	$ 78,543,446	$ 30,901,274	$ 53,099	$ 8,295,954	$ 400,444	$ 17,423	$ 26,441,450
Revenue Change ($)	$ 7,309,999	3,628,542	1,427,574	2,453	127,585	6,158	268	406,647
Proposed Revenue	$ 189,277,150	$ 82,171,987	$ 32,328,848	$ 55,552	$ 8,423,539	$ 406,602	$ 17,691	$ 26,848,097
Revenue Change based on Annualized Current Revenue (%)	4.0%	4.6%	4.6%	4.6%	1.5%	1.5%	1.5%	1.5%
Service Classification Rate Change as a Percentage of Overall Distribution Change		1.15	1.15	1.15	0.38	0.38	0.38	0.38

	LGS-S	GS-P	GS-T	Street Lighting Service OL	Street Lighting Service ORL
Annualized Current Distribution Revenue	$ 7,597,332	$ 19,983,768	$ 423,715	$ 9,286,420	$ 22,826
Revenue Change ($)	350,981	923,208	6,516	429,013	1,055
Proposed Revenue	$ 7,948,313	$ 20,906,976	$ 430,231	$ 9,715,433	$ 23,881
Revenue Change based on Annualized Current Revenue (%)	4.6%	4.6%	1.5%	4.6%	4.6%
Service Classification Rate Change as a Percentage of Overall Distribution Change	1.15	1.15	0.38	1.15	1.15

Current Customer Charges as Percent of Cost of Service

	Residential	Residential Space Heating	General Serv Secondary Sm	General Serv Secondary Large	General Serv Primary	General Serv Transmission	Street Lighting Service
Customer Charge Revenue	$ 21,655,813	$ 8,433,382	$ 7,491,323	$ 994,858	$ 1,814,622	$ 229,514	$ 8,210,698
Total Revenue	$ 78,596,545	$ 30,901,274	$ 35,155,271	$ 7,597,332	$ 19,983,768	$ 423,715	$ 9,306,272
Customer Charge % Cost of Service	27.6%	27.3%	21.3%	13.1%	9.1%	54.2%	88.2%

Source: Marlene C. Santacecilia, Direct Testimony, Schedule (MCS)-1.

Summary of Company's Present and Proposed Rates and Recommended Rates

Description	Company's Present Rate	Company's Proposed Rate	Increase %	Recommended Rates	Increase %
Residential (R)					
Customer Charge	$ 9.35	$ 13.98	49.5%	$ 9.78	4.6%
Distribution Energy Rate	$ 0.029212	$ 0.032211	10.3%	$ 0.030562	4.6%
Residential Space Heating (RSH)					
Customer Charge	$ 9.35	$ 13.98	49.5%	$ 9.78	4.6%
Distribution Energy Rate	$ 0.022938	$ 0.029636	29.2%	$ 0.023998	4.6%
Residential Time of Use Non-Demand (RTOU-ND)					
Customer Charge	$ 14.38	$ 20.39	41.8%	$ 15.04	4.6%
Distribution Energy Rate					
On-Peak	$ 0.050182	$ 0.053465	6.5%	$ 0.052499	4.6%
Off-Peak	$ 0.005494	$ 0.005676	3.3%	$ 0.005748	4.6%
Small General Service - Non Demand (SGS-ND)					
Customer Charge	$ 10.61	$ 12.54	18.2%	$ 11.08	4.4%
Distribution Energy Rate	$ 0.044484	$ 0.048491	9.0%	$ 0.044615	0.3%
General Service Space Heating (GS-SH)					
Minimum Charge	$ 5.60	$ 5.60	0.0%	$ 5.85	4.4%
Distribution Energy Rate	$ 0.018699	$ 0.020914	11.8%	$ 0.018977	1.5%
General Service Water Heating (GS-WH)					
Minimum Charge	$ 5.60	$ 5.60	0.0%	$ 5.85	4.4%
Distribution Energy Rate	$ 0.018895	$ 0.021330	12.9%	$ 0.019128	1.2%
Outdoor Recreational Lighting (ORL)					
Customer Charge	$ 10.61	$ 12.54	18.2%	$ 11.08	4.4%
Distribution Energy Rate	$ 0.030442	$ 0.033555	10.2%	$ 0.031861	4.7%
Medium General Service - Secondary (MGS-S)					
Customer Charge	$ 32.28	$ 48.09	49.0%	$ 33.71	4.4%
Distribution Demand	$ 4.639404	$ 4.793566	3.3%	$ 4.678866	0.9%
Distribution Energy Rate	$ 0.003341	$ 0.003341	0.0%	$ 0.003369	0.9%
Large General Service - Secondary (LGS-S)					
Customer Charge	$ 202.66	$ 202.66	0.0%	$ 202.66	0.0%
Distribution Demand	$ 4.121603	$ 5.121220	24.3%	$ 4.340700	5.3%
Distribution Energy Rate	$ -	$ -	NA		NA
General Service Primary (GS-P)					
Customer Charge	$ 298.90	$ 600.65	101.0%	$ 312.71	4.6%
Distribution Demand	$ 3.332576	$ 4.286308	28.6%	$ 3.486534	4.6%
General Service Transmission (GS-T)					
Customer Charge	$ 2,732.31	$ 4,098.86	50.0%	$ 2,809.89	2.8%
Distribution Demand	$ 0.102055	$ 0.102055	0.0%	$ 0.102055	0.0%

Summary of Company's Present and Proposed Rates and Recommended Rates

Description	Est. Mo. Avg. KWH	Company's Present Monthly Charge	Company's Proposed Monthly Charge	Increase %	Recommended Monthly Charge	Increase %
INC						
2500						
A	69	$ 7.69	$ 9.26	20.5%	$ 8.05	4.7%
Mvo						
8600						
A	70	$ 6.19	$ 7.46	20.5%	$ 6.48	4.7%
Mve						
4200						
A	46	$ 5.66	$ 6.82	20.5%	$ 5.92	4.7%
B	46	$ 11.42	$ 13.76	20.5%	$ 11.95	4.7%
E	46	$ 1.32	$ 1.59	20.5%	$ 1.38	4.7%
8600						
A	70	$ 7.24	$ 8.72	20.5%	$ 7.58	4.7%
B	70	$ 13.04	$ 15.71	20.5%	$ 13.65	4.7%
C	70	$ 12.41	$ 14.95	20.5%	$ 12.99	4.7%
D	70	$ 5.12	$ 6.17	20.5%	$ 5.36	4.7%
E	70	$ 2.02	$ 2.43	20.5%	$ 2.11	4.7%
12100						
A	99	$ 9.26	$ 11.16	20.5%	$ 9.69	4.7%
B	99	$ 15.01	$ 18.08	20.5%	$ 15.71	4.7%
D	99	$ 6.68	$ 8.05	20.5%	$ 6.99	4.7%
E	99	$ 2.86	$ 3.45	20.5%	$ 2.99	4.7%
22500						
A	155	$ 11.66	$ 14.05	20.5%	$ 12.21	4.7%
B	155	$ 17.44	$ 21.01	20.5%	$ 18.26	4.7%
E	155	$ 4.47	$ 5.39	20.5%	$ 4.68	4.7%
63000						
A	374	$ 17.38	$ 20.94	20.5%	$ 18.19	4.7%
HPSo						
5800						
A	36	$ 5.98	$ 7.20	20.5%	$ 6.26	4.7%
9500						
A	49	$ 6.35	$ 7.65	20.5%	$ 6.65	4.7%
HPSe						
4000						
A	21	$ 6.29	$ 7.58	20.5%	$ 6.58	4.7%
E	21	$ 0.58	$ 0.70	20.5%	$ 0.61	4.7%
5800						
A	36	$ 7.12	$ 8.58	20.5%	$ 7.45	4.7%
E	36	$ 1.00	$ 1.20	20.5%	$ 1.05	4.7%
9500						
A	49	$ 7.52	$ 9.06	20.5%	$ 7.87	4.7%
C	49	$ 5.10	$ 6.14	20.5%	$ 5.34	4.7%
D	49	$ 5.05	$ 6.08	20.5%	$ 5.29	4.7%
E	49	$ 1.42	$ 1.71	20.5%	$ 1.49	4.7%

Summary of Company's Present and Proposed Rates and Recommended Rates

Description	Est. Mo. Avg. KWH	Company's Present Monthly Charge	Company's Proposed Monthly Charge	Increase %	Recommended Monthly Charge	Increase %
16000						
A	69	$ 8.33	$ 10.04	20.5%	$ 8.72	4.7%
E	69	$ 2.00	$ 2.41	20.5%	$ 2.09	4.7%
22000						
E	87	$ 2.52	$ 3.04	20.5%	$ 2.64	4.7%
25000						
A	109	$ 12.87	$ 15.50	20.5%	$ 13.47	4.7%
B	109	$ 18.61	$ 22.42	20.5%	$ 19.48	4.7%
D	109	$ 8.96	$ 10.79	20.5%	$ 9.38	4.7%
E	109	$ 3.14	$ 3.78	20.5%	$ 3.29	4.7%
37000						
E	130	$ 3.73	$ 4.49	20.5%	$ 3.90	4.7%
50000						
A	164	$ 15.22	$ 18.34	20.5%	$ 15.93	4.7%
B	164	$ 20.95	$ 25.24	20.5%	$ 21.93	4.7%
D	164	$ 10.98	$ 13.23	20.5%	$ 11.49	4.7%
E	164	$ 4.72	$ 5.69	20.5%	$ 4.94	4.7%
130000						
E	378	$ 10.88	$ 13.11	20.5%	$ 11.39	4.7%
MH						
34000						
A	155	$ 14.39	$ 17.34	20.5%	$ 15.06	4.7%
E	155	$ 4.47	$ 5.39	20.5%	$ 4.68	4.7%
FDS						
6	76	$ 2.18	$ 2.63	20.5%	$ 2.28	4.7%
8	76	$ 2.18	$ 2.63	20.5%	$ 2.28	4.7%
TPS						
40	6	$ 0.16	$ 0.19	20.5%	$ 0.17	4.7%
80	18	$ 0.51	$ 0.61	20.5%	$ 0.53	4.7%
120	30	$ 0.83	$ 1.00	20.5%	$ 0.87	4.7%
160	38	$ 1.08	$ 1.30	20.5%	$ 1.13	4.7%
1		$ 3.22	$ 3.88	20.4%	$ 3.37	4.6%
2A		$ 5.78	$ 6.96	20.4%	$ 6.05	4.6%
2B		$ 5.79	$ 6.97	20.4%	$ 6.06	4.6%
2C		$ 10.28	$ 12.38	20.4%	$ 10.75	4.6%
2D		$ 15.42	$ 18.57	20.4%	$ 16.13	4.6%
2E		$ 19.83	$ 23.88	20.4%	$ 20.75	4.6%
2F		$ 5.77	$ 6.95	20.4%	$ 6.04	4.6%
2G		$ 15.42	$ 18.57	20.4%	$ 16.13	4.6%
3A		$ 16.76	$ 20.18	20.4%	$ 17.53	4.6%
3B		$ 11.57	$ 13.93	20.4%	$ 12.10	4.6%

Source: Marlene C. Santacecilia, Direct Testimony, Schedule (MCS)-1.

Survey of Customer Charges

State	Company	Customer Charge ($/month) Residential	Commercial
DC	Potomac Electric Power Company (Pepco)	$ 9.25	$ 15.76
DE	Delmarva Power & Light Company	$ 13.98	$ 12.54
MD	Baltimore Gas and Electric Company	$ 7.50	$ 11.50
MD	Delmarva Power & Light Company	$ 7.15	$ 18.21
MD	The Potomac Edison Company	$ 5.00	$ 2.57
MD	Potomac Electric Power Company (Pepco)	$ 6.78	$ 10.43
NJ	Atlantic City Electric Company	$ 3.00	$ 5.21
NJ	Jersey Central Power & Light Company[1]	$ 2.20	$ 3.25
NJ	Public Service Electric and Gas Company[2]	$ 2.27	$ 3.96
NJ	Rockland Electric Company	$ 3.88	$ 14.00
NY	Central Hudson Gas & Electric Corporation	$ 24.00	$ 35.00
NY	Consolidated Edison Company of New York, Inc.	$ 15.76	$ 26.01
NY	New York State Electric & Gas Corporation	$ 15.11	$ 5.37
NY	Niagara Mohawk Power Corporation	$ 17.00	$ 21.02
NY	Orange and Rockland Utilities, Inc.	$ 18.00	$ 18.00
NY	Rochester Gas and Electric Corporation	$ 21.38	$ 21.38
PA	Duquesne Light Company	$ 7.00	$ 30.00
PA	Metropolitan Edison Company	$ 8.11	$ 10.88
PA	PECO Energy Company	$ 7.09	$ 13.12
PA	Pennsylvania Electric Company (Penelec)	$ 7.98	$ 7.73
PA	Pike County Light & Power Company	$ 6.25	$ 10.00
PA	UGI Utilities, Inc.	$ 5.50	$ 6.75
PA	West Penn Power Company	$ 5.00	$ -

[1]Residential Supplemental Customer Charge: $1.14 per month Off-Peak/Controlled Water Heating; General Service Supplemental Customer Charge: $1.14 per month Off-Peak/Controlled Water Heating, $2.66 per month Day/Night Service, and $12.10 per month Traffic Signal Service.
[2]These rates exclude New Jersey's Sales and Use Tax.
Source: Tariffs.

Comparison of Customer-Related Costs Under Company's Recommended CCOSS

	Total DE	Residential	Residential Space Heating	General Serv Secondary Sm	General Serv Secondary Large	General Serv Primary	General Serv Trans-mission	Street Lighting Service	Traffic Lights
Customer Meters	$ 15,957,554	$ 8,044,494	$ 2,817,424	$ 3,580,528	$ 178,573	$ 1,301,848	$ 17,610	$ 17,078	$ 0
Customer Services	6,075,564	3,784,199	1,412,576	863,370	15,418	0	0	0	0
Meter Reading Expenses	4,480,870	2,690,364	987,326	781,589	8,958	11,916	132	584	0
Customer Records Expenses	28,236,831	17,464,444	6,764,527	3,665,609	47,465	59,101	1,353	209,508	24,823
Customer Services Expenses	3,144,829	1,314,868	556,447	444,928	130,060	511,949	154,257	31,475	846
Customer Sales Expenses	641,442	270,293	110,665	99,799	27,002	101,513	25,457	6,539	174
Customer - Other Expenses	14,820,519	2,670,666	1,079,002	871,258	373,089	1,519,951	386,880	7,870,958	48,716
Total Customer-Related Costs	$ 73,357,609	$ 36,239,329	$ 13,727,967	$ 10,307,080	$ 780,565	$ 3,506,278	$ 585,689	$ 8,136,142	$ 74,559
Average No. Customers	306,503	193,118	75,484	32,154	405	496	7	4,820	19
Monthly Customer-Related Costs/Customer	$ 19.94	$ 15.64	$ 15.16	$ 26.71	$ 160.61	$ 589.09	$ 6,972.48	$ 140.67	$ 327.01
Customer Charge Revenue	$ 49,979,055	$ 21,655,813	$ 8,433,382	$ 7,491,323	$ 994,858	$ 1,814,622	$ 229,514	$ 9,359,542	$ -
Monthly Customer Charge Revenue/Customer	$ 13.59	$ 9.34	$ 9.31	$ 19.42	$ 204.70	$ 304.88	$ 2,732.31	$ 161.82	$ -
Relationship of Customer Charge Revenues to Customer-Related Costs	0.68	0.60	0.61	0.73	1.27	0.52	0.39	1.15	0.00

Source: Elliott P. Tanos, Direct Testimony, Schedule (EPT)-1; Marlene C. Santacecilia, Direct Testimony, Schedule (MCS)-1.

Responses to Data Requests Referenced in Testimony and Schedules

Responses to Data Requests Referenced in Testimony and Schedules

Data Request AG-REL-36
Data Request AG-REL-37
Data Request PSC-REL-9
Data Request AG-REL-8
Data Request AG-REL-7
Data Request PSC-REL-18
Data Request AG-REL-11
Data Request PSC-REL-8
Data Request PSC-COS-18
Data Request PSC-COS-28
Data Request PSC-COS-29
Data Request AG-COS-16
Data Request PSC-COS-22
Data Request AG-GEN-10
Data Request AG-COS-19
Data Request AG-COS-25
Data Request AG-RD-25
Data Request AG-RD-44
Data Request PSC-CP-6
Data Request AG-GEN-1
Data Request AG-REL-1

PSC DOCKET NO. 13-115
ATTORNEY GENERAL OF THE STATE OF DELAWARE
FIRST SET OF RELIABILITY DATA REQUESTS
TO DELMARVA POWER & LIGHT COMPANY

Question No. : AG-REL-36

Re: Boyle Direct, page 2 line 21 to page 3 line 11, referring to the linkage between Company under-earning and continued implementation of major reliability enhancements.

a. Provide any and all analyses demonstrating the linkage between the Company's under-earnings and the implementation of major reliability enhancements.
b. Provide any and all analyses which quality the under-earnings associated with the major reliability projects.
c. Disaggregate the under-earnings associated with the reliability investment, non-reliability investment, increases in expenses, changes in the cost of capital, and any other major factors (identify), that impact the Company's earnings.
d. To the extent not provided in response to (b), describe each reliability project and the investments associated with each project which resulted in under-earnings.
e. Provide all workpapers and source documents supporting the Company's response in electronic form, with all spreadsheet links and formulas intact, source data used, and explain all assumptions and calculations used. To the extent the data requested is not available in the form requested, provide the information in the form that most closely matches what has been requested.

RESPONSE:

The requested analyses have not been performed. Company Witness Boyle's testimony on page 2 line 21 to page 3 line 11 provides multiple causes for the Company's under earnings including reliability enhancements, low customer growth, and the use of historic rate base.

Respondent: Frederick J. Boyle

PSC DOCKET NO. 13-115
ATTORNEY GENERAL OF THE STATE OF DELAWARE
FIRST SET OF RELIABILITY DATA REQUESTS
TO DELMARVA POWER & LIGHT COMPANY

Question No.: AG-REL-37

Re: statement in Boyle Direct, page 3 lines 3-6 that "Despite this cycle of under earning, Delmarva has continued its implementation of major reliability enhancements, requiring significant amounts of capital, which address both infrastructure replacement and system enhancements."

a. Identify the total dollar amount of the Company's under-earnings by year for each year in the "cycle" to which Mr. Boyle refers.
b. Define "cycle" as the Company uses the word in the cited context.
c. Provide the Company's calculations of the under-earning amount for each cycle.
d. Define "significant" as the Company uses the word in the cited context and quantify the significant amount of capital necessary to "address infrastructure replacement and system enhancements" by year.
e. Define "system enhancement" as the Company uses it in the cited context.
f. Define "infrastructure replacements" as the Company uses it in the cited context.
g. Explain in detail the difference between what the Company defines as "system enhancements" versus what the Company defines as "infrastructure replacements."
   1. Identify which reliability programs the Company would classify as system enhancements, and state the amount of expenditures (including and excluding AFUDC) associated with these enhancements. Provide the requested information for the last ten years, as included in the test year rate base, as included in the reliability proforma adjustment, and as projected for the next five years.
   2. Identify which reliability programs the Company would classify as infrastructure replacements and quantify the total amount proposed for each program.

RESPONSE:

a. Refer to the response to AG-REL-36. Also, see Table 1 in the testimony of Company Witness Ziminsky on page 37 line 1, which provides the Company's under earnings from 2008 to 2012.

b. The Company's definition of "cycle" as used in the cited context is the continuous period of time that the Company has not earned its authorized return on equity. As stated in the testimony of Company Witness Ziminsky on page 36 line 17 to page 37 line 7, the Company has not earned its authorized return on equity for the last six calendar years.

c. See part a above.

d. The Company's definition of "significant" as used in the cited context is Delmarva's 2012 and 2013 construction budgets of $374.4 million as stated in the testimony of Company Witness Maxwell.

e and f. Delmarva does not classify reliability projects according to "replacements" versus "enhancements." Generally speaking, a replacement would be a one to one replacement of equipment, while an enhancement would be any reliability work that improves reliability performance.

g. 1. Refer to the response to AG-GEN-1 Attachment A, B, and D for available information. The requested projection of the reliability proforma adjustment has not been performed.

2. See response to parts e.-g.

Respondent: Michael W. Maxwell/Frederick J. Boyle

PSC DOCKET NO. 13-115
DELAWARE PUBLIC SERVICE COMMISSION STAFF
FOLLOW UP SET OF RELIABILITY DATA REQUESTS
TO DELMARVA POWER & LIGHT COMPANY

Question No. : PSC-REL-9

Please refer to the projects in AG-REL-3 Attachment A.

(a) Please identify what measures of reliability or indices each project was designed to impact, and any data available on the change the company has identified due to the individual project, or group of similar projects.
(b) Identify if the project was meant to impact (1) reliability during conditions measured in IEEE indexes (i.e., non-major events), (2) reliability during events excluded from IEEE (i.e., major events), (3) the speed of restoration after major events, or (4) customer costs during an outage event.
(c) For each individual projects shown, please clarify if the project was designed to benefit only Delaware customers or if it was designed to benefit both Delaware and Maryland customers.
(d) Please identify the reliability enhancement plan projects included in Adjustment 26 that are not shown in AG-REL-3 Attachment A and answer question (c) for those projects.

RESPONSE:

a. The company selects and designs all reliability projects to decrease the frequency and duration of outages on the selected feeders. The requested data surrounding the changes at an individual project level is not available.

b. The REP is primarily focused on reliability data that excludes major events, but the benefits of most of the REP projects are transferable to major storms as well.

c. All projects listed are designed to benefit Delaware customers.

d. All projects listed below are designed to benefit Delaware customers.

WBS Element	Reliability Project Delaware District Location and Description	State
UDLBRM3M1	Millsboro District Emergency Repair/Replacements Distribution Line Equipment	Delaware
UDLBRM4MA	Millsboro District Reliability/District Office Minor Distribution System Improvements	Delaware
UDLBRM4ME	Millsboro District Deteriorated Pole Replacement	Delaware
UDLBRM4MH	Millsboro District Avian Protection	Delaware
UDLBRM4MJ	Millsboro District Planned Replacement of Distribution Reclosers	Delaware
	Millsboro District Customer Reliability Improvements	Delaware

UDLBRM4MM		
UDLBRM4MQ	Millsboro District Distribution Upgrades to Devices Experiencing Multi Operations	Delaware
UDLBRM4RC	Bishop Substation - Lines Upgrade - DE	Delaware
UDLBRM5ND	Millsboro District Line Upgrades for NERC Compliance	Delaware
UDLNRM3C1	Christiana District Emergency Repair/Replacements Distribution Line Equipment	Delaware
UDLNRM4CA	Millsboro District Reliability/District Office Minor Distribution System Improvements	Delaware
UDLNRM4CE	Christiana District Deteriorated Pole Replacement	Delaware
UDLNRM4CH	Christiana District Avian Protection	Delaware
UDLNRM4CJ	Christiana District Planned Replacement of Distribution Reclosers	Delaware
UDLNRM4CM	Christiana District Customer Reliability Improvements	Delaware
UDLNRM4CQ	Christiana District Distribution Upgrades to Devices Experiencing Multi Operations	Delaware
UDLNRM4CR	Wilmington Network Upgrade	Delaware
UDLNRM5ND	Christiana District Line Upgrades for NERC Compliance	Delaware
UDLNRM5SC	Christiana District Christiana Substation Feeder relocation	Delaware
UDLNRM5SD	Christiana District Reconductor Feeder DE0217	Delaware
UDLNRM5SE	Christiana District Cable Replacement for New Substation Switch Gears	Delaware
UDLNRM8SE	Christiana District.-Rebuild Overhead Rear Lot Distribution System	Delaware
UDLNRM8SH	Churchmans Substation - Replace Reclosers	Delaware
UDLNRM9SB	Christiana District Replace Steel Poles along 4th St. Wilm	Delaware
UDLNRMT1	Christiana District MILLTOWN RD - MOVE DE0640 FROM T1 TO T3	Delaware
UDSBRD71D	Millsboro District Emergency Repair/Replacements Distribution Sub Equipment	Delaware
UDSBRD8AD	Millsboro District Substation Planned Improvements	Delaware
UDSBRD8BD	Millsboro District Misc Relay Blanket	Delaware
UDSBRD8DD	Millsboro District Laurel substation - DPU Replacement	Delaware
UDSBRD8ED	Millsboro District Distribution Substation Battery Replacements	Delaware
UDSBRD8FD	Millsboro District Distribution Substation Bushing Replacements	Delaware
UDSBRD8G	Millsboro District - PHI Spare Transformers	Delaware

Respondent: Michael W. Maxwell

PSC DOCKET NO. 13-115
ATTORNEY GENERAL OF THE STATE OF DELAWARE
FIRST SET OF RELIABILITY DATA REQUESTS
TO DELMARVA POWER & LIGHT COMPANY

Question No.: AG-REL-8

Provide all studies, analyses, evaluations or reports undertaken by or on behalf of the Company for the purpose of examining the cost versus benefit or cost-effectiveness of infrastructure investments as proposed in this proceeding and as planned for the next five years. Provide all supporting workpapers and source documents in electronic spreadsheet form, with all links and formulas intact, source data used, and explain all assumptions and calculations used. To the extent the data requested is not available in the form requested, provide the information in the form that most closely matches what has been requested.

RESPONSE:

The requested analysis has not been performed.

Respondent: Michael W. Maxwell

PSC DOCKET NO. 13-115
ATTORNEY GENERAL OF THE STATE OF DELAWARE
FIRST SET OF RELIABILITY DATA REQUESTS
TO DELMARVA POWER & LIGHT COMPANY

Question No. : AG-REL-7

Provide copies of all value-of-service studies prepared by or on behalf of the Company. If no such studies were prepared, provide a detailed explanation for why Delmarva did not prepare such studies.

RESPONSE:

Delmarva objects to this data request on grounds that the phrase "value of service studies" is vague and ambiguous in that there is no attempt to define the phrase. Without waiving any objection, see response to AG-REL-8.

Respondent: Delmarva

PSC DOCKET NO. 13-115
DELAWARE PUBLIC SERVICE COMMISSION STAFF
FOLLOW UP SET OF RELIABILITY DATA REQUESTS
TO DELMARVA POWER & LIGHT COMPANY

Question No. : PSC-REL-18

Please refer to the response to AG-REL-8.

(a) Please clarify if the company's response means that it has no documentation to illustrate that the projects were constructed in an economic manner.
(b) Please also reconcile this response with the response to AG-REL-11.
(c) Please clarify if the company launched the Asset Management Administrative Procedure (referenced in the attachment to AG-REL-11) in 2010 and if not, please supply the launch date.

RESPONSE:

a) No, AG-REL-8 specifically asked for "studies, analyses, evaluations or reports," "examining the cost versus benefit or cost-effectiveness of infrastructure investments." Delmarva uses many methods to ensure projects are constructed in an economic manner, including competitive bidding of material and resource, and standard engineering design and work practices to ensure that the work is performed in a way to meet all appropriate standards. In this way each project will used the type of material that provides the greatest long term benefit for the system and allows for consistent work practices for ongoing maintenance of the distribution system. The responses were only intended to convey that the company does not engage in traditional economic analysis of work because the costs, measured in dollars, and the benefits accrued, measured in reliability performance, do not lend themselves to those forms of analysis.
b) AG-REL-11 provides a description of how Delmarva develops and plans its budgets and forecasts.
c) Yes, the Asset Management Administrative Procedure was launched in 2010.

Respondent: Michael W. Maxwell

PSC DOCKET NO. 13-115
ATTORNEY GENERAL OF THE STATE OF DELAWARE
FIRST SET OF RELIABILITY DATA REQUESTS
TO DELMARVA POWER & LIGHT COMPANY

Question No.: AG-REL-11: Reliability Projects

a. Provide all evaluations and analyses undertaken by or on behalf of the Company in the last five years for the purpose of identifying projects related to improving reliability and repairing or replacing aging or obsolete facilities.
b. For each of the last five years, list all of the potential projects identified by the Company for improving electric service reliability.
c. For each project listed in your response to part (b), state:
   1. Whether the Company approved the project;
   2. Whether the Company did not approve the project; and
   3. The priority given the project by the Company.
d. Provide all workpapers and source documents supporting the Company's response in electronic form, with all spreadsheet links and formulas intact, source data used, and explain all assumptions and calculations used. To the extent the data requested is not available in the form requested, provide the information in the form that most closely matches what has been requested.

RESPONSE:

a. On an annual basis, Delmarva approves its budget year construction plan and its four year construction forecast. Similarly, on an annual basis Delmarva approves its O&M budget for the coming year. Delmarva approves these budgets and implements them throughout the year making capital investments and incurring expenses that are necessary for the ongoing provision of safe and reliable electric distribution service.

Delmarva endeavors to make the appropriate use of its resources and to contain its expenditures to the appropriate levels to obtain its objectives of safe and reliable electric distribution service in the current period and on an ongoing basis.

Delmarva's five year Distribution Construction expenditures at the detailed project (WBS) level and can be found at AG-GEN-1 Attachment A.

The Company uses estimating techniques / appropriate for the capital budgeting process that develops the five-year plan. In turn, these estimating techniques that are appropriate for use in the five-year planning process are significantly enhanced by more detailed methods for establishing the approval and control of individual Work Requests (WR) to design and construct specific units of property.

The evaluations of distribution investments are accomplished within the Work Request (WR) development process that is based on the definitive identification of the scope of work to be accomplished.

It is at the WR scoping, estimating, authorization and control level that the Company identifies the individual estimated costs for building Delmarva assets. The estimated WR costs are developed within the Work Management System and are based on a compatible unit costing system.

This system is regularly updated to reflect current labor rates and man-hours required to perform individual units of work.

The material costs are based on current system average costs for each specific material item and together produce estimated costs that are reflective of the actual costs to perform the work.

Reliability projects included in the annual five-year construction plan include significant ongoing programs such as feeder improvements, priority feeders, underground residential distribution (URD) cable replacements, customer reliability improvements, voltage conversions, substation equipment replacement, etc. Load projects contain fewer numbers of projects but represent significant ongoing programs such as feeder extensions, new substations, load transfers, and power transformer additions.

Refer also to the response provided to AG-GEN-6. Also, see the attached "PHI Equipment Condition Assessment Process" AG-REL-11 Attachment.

b. The Company only maintains a list of approved projects. A potential project that was not approved is not recorded or maintained. Refer to the response to AG-GEN-1 Attachments A for a list of actual expenditures for approved projects.

c. See attachments referenced above.

d. Delmarva objects to this request on grounds that it is overly broad and unduly burdensome. Without waiving any objection, see materials and produced in response to these data requests.

Respondent: Michael W. Maxwell

Pepco Holdings Inc

PHI / Asset Management / Asset Performance Planning
Administrative Procedure

AD214
Revision 2

PHI EQUIPMENT CONDITION ASSESSMENT PROCESS

Reviewed: *Carl S. Kapes* Date: 01/29/10
Consulting Engineer – Asset Performance Planning

Approved: *Ken Lehberger* Date: 05/05/10
Manager – Electric Maintenance ACE Region

Approved: *Dave Lucas* Date: 05/05/10
Manager – Electric Maintenance DPL Region

Approved: *Mary Pekot* Date: 05/05/10
Manager – Electric Maintenance PEPCO Region

Approved: *Mostafa Hassani* Date: 05/05/10
Manager – PHI Reliability Engineering

Approved: *Carol Murphy* Date: 05/05/10
Manager – PHI Electric Maintenance

Next Review Date 05/31/12

TABLE OF CONTENTS

1.0 SCOPE

1.1 The purpose of this procedure is to describe the process for assessing equipment condition across PHI in an effort to prioritize available maintenance resources and maximize system reliability. This process will help to ensure that the equipment receives the required maintenance when needed. Even though the input and equipment within this process may vary from region to region across PHI, the process itself should be applied consistently across all the PHI Regions in line with the "One Company – One Process" Philosophy.

1.2 To ensure consistent implementation across PHI and to address dynamic equipment conditions, Equipment Condition Assessment (ECA) Meetings will be conducted quarterly at each PHI Region.

1.3 The scope of work to be discussed during the ECA Meetings will primarily consist of, but is not limited to, existing and proposed condition-based Preventative Maintenance (PM) and any applicable Supplemental Maintenance (SM). Other work tasks, such as Preventative/Predictive Maintenance (PM/PdM) and Corrective Maintenance (CM) Tasks, will only be discussed as needed. Existing or proposed Capital Work Projects will also be discussed, when applicable.

1.3.1. Predictive Maintenance (PdM) is defined as cyclical inspections, tests or even samples resulting from time-based or count-based maintenance identified as defined by PHI's Reliability Centered Maintenance (RCM) Program. These tasks must be funded and implemented to ensure the continued safe and reliable operation of all equipment and systems throughout the PHI service territory.

1.3.2. Preventative Maintenance (PM) is defined as any condition based repairs, replacements, calibrations, cleanings, treatments, or lubrications that have been identified as a result of Predictive Maintenance (PdM) Activities. Preventative Maintenance is performed prior to equipment or system failure.

1.3.3. Supplemental Maintenance (SM) is defined as unforeseeable or additional (>10% labor) Preventative Maintenance (PM) that is discovered during the performance of any Predictive or Preventative Maintenance Activities and is determined to be necessary to avoid equipment or system failure.

1.3.4. Corrective Maintenance (CM) is defined as reactive non-capital work necessary to restore the operability of failed equipment or a system.

1.4 The ECA Process will primarily use the following technologies to provide input for prioritization and to determine what further maintenance may be necessary;

1.4.1. Chemical Analysis (refer to Attachment 3.1, Chemical Analysis / LTC and Breaker Oil Ranking Process).

1.4.2. Electrical Testing Analysis (refer to Attachment 3.2, Electrical Testing Analysis / Equipment and Maintenance History Process).

1.4.3. Predictive maintenance tool analysis (refer to Attachment 3.3, Predictive Maintenance Ranking Process).

1.4.4. LTC and breaker operation (refer to Attachment 3.4, LTC Operational Ranking Process).

2.0 INSTRUCTIONS

2.1 RESPONSIBILITIES

2.1.1. The Manager of Asset Reliability & Performance (ARP) Engineering is responsible for revisions to, and approval of this procedure, as well as the adherence by Asset Management personnel.

2.1.2. Designated Asset Management personnel are responsible for;

1. Planning and conducting the quarterly ECA Meetings within each PHI Region.
2. Providing Chemical Analysis Data and other applicable information for discussion during the quarterly meetings.
3. Documenting, publishing and maintaining ECA priorities quarterly for each PHI Region.
4. Ensuring the appropriate funding can be allocated to support the required maintenance.
5. Creating SAP-PM notifications when conditions adverse to quality arise from applicable data analysis.

2.1.3. The PHI and Regional Managers of Electric Maintenance are responsible for assuring that Regional Maintenance personnel adhere to this procedure.

2.1.4. The Maintenance Supervisors are responsible for ensuring that the maintenance work is completed and documented in SAP-PM and that the work order packages are timely forwarded to a Technical Analyst/Planner within the applicable PHI Region.

2.1.5. Engineers and/or Technical Analyst/Planners within the Operations Department are responsible for;

1. Collecting and storing equipment inspection/test data and performing trend/condition analyses.
2. Making the trend/condition analyses available for quarterly ECA Meetings and discussing any possible adverse results.
3. Creating and/or approving SAP-PM notifications and work requests as determined through the ECA Process meetings.
4. Populating proper priorities and completion dates within SAP-PM.
5. Updating SAP-PM work statuses and adjusting the priority of work orders, as required.

6. Closing (TECO'ing) SAP-PM work orders within two business weeks or by the 3rd business day of the following month, whichever occurs first, after completing the actual field work.

NOTE: The actual completion-in-the-field date should be assigned for the TECO reference date status in SAP-PM.

7. Providing appropriate work prioritization and progress reports on the work requests to Asset Management personnel for Key Performance Indicator (KPI) Reporting.

2.2 EQUIPMENT CONDITION ASSESSMENT PRIORITIZATION AND DATA ANALYSES

2.2.1. An individual prioritization list will be established for each PHI Region, per major equipment class, and will be revised, if necessary, during each quarterly ECA Meeting and as new work is identified.

2.2.2. The regional prioritization list will consist mostly of proposed condition-based type maintenance tasks and these tasks will be ranked from highest to lowest in order of priority.

1. Prioritization lists will be broken into major equipment categories per PHI Region.
2. The highest ranked task will be given a ranking of "1," per major equipment category.
3. The lowest ranked task will be based on how many approved tasks exist.
4. There is no set limit of tasks that can ranked, however available funding to complete some tasks may be limited.
5. Unranked tasks are those deemed as not appropriate and will not be funded for the time being, but will still be tracked through ECA.
6. Funding will be available, per major equipment category, from a top down approach. The highest priorities are given the most budget consideration. Not all items ranked will be funded within the current year, but may continue to carry and be re-ranked on the lists until resolved in future cycles.

2.3 EQUIPMENT CONDITION ASSESSMENT WORK FLOW PROCESS

2.3.1. All identified maintenance tasks shall be input into SAP-PM via the notification process by any individual or group responsible for identifying the condition.

2.3.2. All applicable SAP-PM notifications, new work orders and existing work orders in the applicable region will be discussed and prioritized/re-prioritized during each quarterly ECA Meeting.

2.3.3. Once work is approved and prioritized during the quarterly ECA meetings, the SAP-PM notifications shall be rolled to work orders by the Maintenance Engineers, Technical Analyst/Planners or Supervisors so the work can be scheduled and completed in the field.

2.3.4. The Equipment Condition Assessment (ECA) prioritization to be established in SAP-PM notifications and work orders is shown in the following table;

SAP-PM Condition	Maintenance Action
Immediate	Immediately (subject to resource availability)
High	Within 3 months (subject to resource availability)
Within Schedule	As scheduled (within the year)
Low	Deferrable (if associated risk of not doing work is low).

2.3.5. Designated Asset Management personnel will publish the results of each individual ECA meeting, by Region, on the PHI Manage System Maintenance Intranet site within 10 business days of the completion of the applicable ECA Meeting.

2.3.6. Funding through the PHI Reliability Plan will be based on and adjusted to the priorities established through the ECA Process by appropriate Asset Management personnel.

2.3.7. Once the work is completed in the field, SAP-PM work orders shall be statused as 50 – MCMP – Maintenance Complete and TECO'd within two business weeks or by the 3rd business day of the following month, whichever occurs first, by the designated Maintenance Engineer, Technical Analyst/Planner or Supervisor.

2.3.8. Completed work items will then be discussed during the next applicable ECA meeting and will be removed from the prioritization list described above.

2.3.9. Any item designated as "Capital" will then be discussed with the appropriate engineering area and be tracked through Capital Budgeting & Ranking Process. The item will continue to be tracked as "Capital" on the appropriate ECA List until it is finally replaced in the field.

2.4 DOCUMENTATION AND WORK TRACKING PROCESS

2.4.1. The Technical Analyst/Planner in conjunction with the Maintenance Supervisors will ensure that:

1. All paper and electronic records of the completed maintenance tasks associated with the ECA and Predictive/Preventative Maintenance Processes are properly completed and filed for easy access and review.
2. All appropriate work progress records (e.g. SAP-PM, Maintenance Logs, etc) are updated timely and correctly.
3. All work tasks are properly categorized (e.g. predictive, preventive, supplemental, corrective) and that costs are charged to the appropriate accounts.

2.4.2. Asset Reliability Planning Staff will ensure that:

1. Results of quarterly meetings are documented and issued to participants
2. Any necessary maintenance budget adjustments are timely obtained/implemented.
3. Work progress is tracked using Key Performance Indicators based on Maintenance Logs, SAP-PM, and Reports issued as appropriate.

3.0 ATTACHMENTS

3.1 Chemical Analysis – Transformer, LTC, and Breaker Oil Ranking Process and other acceptable industry standards (EPRI, Doble, IEC, IEEE)

3.2 Electrical Testing Analysis / Equipment and Maintenance History Process

3.3 Predictive Maintenance Ranking Process

3.4 LTC Operational Ranking Process

3.5 On-line Gas Monitoring Process

Chemical Analysis – Transformer, LTC, and Breaker Oil Ranking Process

Equipment - Substations transformers, load tap changers and oil circuit breakers.

Inspection / Test - Oil & gas analysis program includes collection, laboratory analysis, data management and recording maintenance recommendations based on results.

Inspection Frequency or Trigger - The inspection frequency is based upon the RCM (Reliability Centered Maintenance) plan and is triggered utilizing applicable SAP-PM Maintenance Plans. Transformer Oil Analyst (TOA), a computer program containing oil analysis standards, is used as the basis for RCM as follows:

1. Description of How RCM Is Linked To TOA

Transformers

- All transformers use TOA analysis rules entitled TR.
- The RCM collection frequency is based on MVA.
- The RCM frequency determines TOA gas standard.

Transformer MVA	RCM in Years	TOA Gas Standard	TOA Fluid Standard
< 10	2	2 TR	OIL TRN
10 – 99	1	1 TR	OIL TRN
> 100	1/2	1/2 TR	OIL TRN

Oil Circuit Breakers (OCB)

- All OCB's use TOA analysis rules entitled OCB.
- The RCM collection frequency is based on type of OCB use.
- The RCM frequency determines TOA gas standard. The number of breaker operations can determine RCM frequency.

Breaker Use	RCM in Months	TOA Gas Standard	TOA Fluid Standard
Cap Bank or Pwr Plant	12	OCB12	OCB12
Feeder	24	OCB24	OCB24
Bus Tie or Transformer	36	OCB36	OCB36

Load Tap Changers (LTC)

- All LTC's use TOA analysis rules entitled OILTC.
- The RCM collection frequency is based on breathing type of LTC.
- The RCM frequency determines TOA gas standard

Transformer MVA	RCM in Years	TOA Gas Standard	TOA Fluid Standard
Free	1	LTC FREE	OIL TC
Sealed	1	LTC SEALED	OIL TC
Vacuum	2	LTC VACUUM	OIL TC

2. Determination Of How Sample Collection Schedule Is Produced:

   SAP-PM, through the use of Maintenance Plans, will automatically call and create an SAP-PM work order for the scheduled execution of the applicable sample. The appropriate sample frequency is already pre-programmed into the SAP-PM Maintenance Plan to ensure samples are drawn at the RCM determined intervals. If any resampling is in order, prior to the next call date, a manual call on the applicable SAP-PM Maintenance Plan will be required.

3. Collection Sheet Guides Collection Process:

   The field mechanic or personnel assigned to oil collection uses these sheets to identify equipment and record field information. The location, equipment number, designation, serial number and owner fields are used to identify the equipment before collection. The date, counter number, syringe number and oil temperature fields are recorded on the sheet at the time of collection. The collection sheet and samples are delivered or sent to the laboratory after completion of the sample.

4. Collection Sheet Guides Flow of Sample through the Laboratory Process:

   The collection sheet accompanies the sample through the laboratory. The laboratory test fields on the collection sheet include DGA, water, color, DBPC inhibitor, acid scan, IFT and breakdown. The laboratory test results are recorded in the appropriate fields of the collection sheet. The DGA results and completed collection sheet information are input to TOA (Transformer Oil Analyst) resident on T drive of the Pepco LAN. The package of collection sheets, DGA results and oil results are sent or presented to the lab supervisor for second level review. The supervisor checks all data and input. Based on the gas and oil analysis, the supervisor assigns overall rating to individual equipment in the Description field of TOA (i.e., 1 DEFER, 2 PERFORM PM, 3 SERIOUS or 4 CRITICAL, RESAMPLE). The Critical items are reported immediately by e-mail and in person to the responsible engineers within both the Asset Management and Operations Organizations.

5. Oil Quality and DGA results are used as an input into the ECA Process:

   The laboratory staff reviews all data as produced. Any laboratory results that indicate a potential equipment problem or condition adverse to quality should be documented by creating a notification in SAP-PM within 5 business days. The laboratory staff also enters the word SAP-PM in the TOA description field and enters a brief description of the requested work and the SAP-PM notification number in TOA remarks. The SAP-PM notification number is included in the Insulating Fluid Analysis Report provided to the supervisor and/or Technical Analyst/Planner for review. These notifications will be discussed during the next applicable ECA Meeting for approval and prioritization. If the condition warrants immediate attention, the applicable supervisor and/or Technical Analyst/Planner shall be notified immediately so the issue can be addressed appropriately.

Electrical Testing Analysis/ Equipment & Maintenance History Process

Transformers

Electrical testing used as input for The ECA Process for oil filled transformers is determined in the following manner. Current and past data from the following tests may be used to evaluate each transformer:

- Winding power factor.
- Winding excitation.
- Winding insulation resistance.
- Winding micro-ohm.
- Winding core ground.
- Winding frequency response analysis.
- Bushing UST (C1) power factor.
- Bushing UST (C2) power factor.
- Bushing "hot collar" watts and current.
- Bushing insulation resistance.
- Insulating oil power factor.

After each data set is analyzed / reviewed, the applicable Maintenance Engineer, Technical Analyst or Supervisor will rate the transformer according to Doble Engineering standards, PHI standards, manufacturer standards, and current industry standards.

Historical trending, individual transformer maintenance records, loading, fault history, bushing type, tap changer type, and secondary bus switch-gear corona test results, and personal knowledge of a specific device or family of devices are also used to rate the device(s).

Circuit Breakers

Electrical testing used as input for The ECA Process of an oil or gas filled circuit breaker is determined in the following manner. Current and past data from the following tests may be used to evaluate each oil or gas filled circuit breaker:

- Open breaker power factor.
- Closed breaker power factor.
- Bushing UST (C1) power factor.
- Bushing UST (C2) power factor.
- Bushing "hot collar" watts and current.
- Insulating oil power factor.
- Open breaker insulation resistance.
- Closed breaker insulation resistance.
- Contact micro-ohm.
- Internal resistor measurements.
- Three phase or single phase motion analyzing.
- Profile P1 timing tests.

After each data set is analyzed and reviewed, the applicable Maintenance Engineer, Technical Analyst or Supervisor will rate the oil or gas filled circuit breaker according to Doble Engineering Standards, PHI Standards, manufacturer standards, and current industry standards.

Historical trending, individual circuit breaker maintenance records, operational data, fault data, bushing type, voltage class, mechanism type, and personal knowledge of a specific device or family of devices are also used to rate the device(s).

Predictive Maintenance Ranking Process

Collect Measurement and Condition Data

Equipment performance data is collected for analysis to determine the optimal condition based maintenance cycle.

Analyze Equipment Performance

The analysis for each type or piece of equipment can require unique analysis tools. These range from EPRI based analysis systems to expert opinion from an experienced staff member.

Time-Based Inspections

Time-based preventative maintenance inspections are based on the established review cycle time for the particular equipment through RCM.

The inspections collect required analysis data required to determine condition and perform condition-based preventative maintenance inspections as required.

Problem Equipment Monitoring

The Electric Maintenance Groups and designated Asset Management personnel monitor transformers, breakers or other equipment that have exhibited unusual behavior in the past. Monitoring is performed with measuring equipment that is physically connected to the device or with an infrared camera. The data is gathered by electronic file transfers, or by physically inspecting equipment and getting measurements. This includes: LTCMAP for Tap changers, P1 Breaker Monitors, an IDD Bushing Monitor, On-line Gas Monitors and Infrared Camera data collection.

Ranking Process

The Infrared Camera is used as the principle tool in detecting temperature differentials in vital components on the transformer. A record of temperature differentials between high temperature components is compared to components operating under normal conditions.

Predictive Maintenance Infrared Ranking Process		
Rank	Condition	Criteria
1	---	---
2	Intermediate	11 – 35 Degrees
3	Serious	36 – 75 Degrees
4	Critical	75 Degrees

LTC Operational Ranking Process

The number of transformer LTC operations can also be used as input into the ECA Process to determine if condition-based preventative maintenance is necessary. Operational Rank is a calculation of the percentage of recommended RCM tap operations to be allowed on a particular tap changer for the purpose of determining if the condition-based preventative maintenance inspection may be necessary.

The tap counter data is collected on a monthly basis from the Operator inspections at the substations. Engineers, Technical Analyst/Planners or Supervisors can review, record and track this data monthly in a spreadsheet or in SAP-PM through Measurement Points/Counters. The following table can be used to determine if a condition based preventative maintenance inspection should be considered or planned;

Percents (%) from last inspection	Rating	Action
0-59	1	None.
60-100	2	Consider Inspection
101-150	3	Plan Inspection for Next Quarter
151 and Up	4	Plan Inspection Immediately

If a tap changer falls into condition 2, 3 or 4 above, an SAP-PM notification shall be written by the individual reviewing the data. SAP-PM Notifications based conditions 3 and 4 above should be discussed immediately with the appropriate Engineers, Technical Analyst/Planners or Supervisors. Condition 2 above can be discussed at the next applicable ECA Meeting. If tap counters are found to be inoperative or defective, an SAP-PM notification shall be generated to have them repaired.

A similar operational rank scoring process is anticipated for Oil Circuit Breakers, but it is not yet formalized or utilized throughout PHI. The Atlantic Region has an informal process which can be used as a starting point for the PHI program process.

On-line Gas Monitoring Process

Equipment – On-line dissolved gas monitors are installed on numerous transformers throughout the PHI service territories. The monitors provide transformer oil dissolved gas results, temperature and moisture readings at least twice a day.

Alarm Limits – Overall gassing and gassing rate-of-change limits are set for each monitored transformer. These limits will vary from transformer to transformer and are based the on gassing history, size, type and load of the individual transformer. The limits can be found within the software used to display and analyze the monitored results.

When alarm limits have been reached or exceeded, the monitors/software will automatically notify those responsible to analyze the data. In some cases, System Operations may also get these alarms so they can also notify those responsible for analysis.

Analysis – Engineers in both the Asset Management and Electric Maintenance Organizations are responsible for periodically reviewing the data to ensure the transformers are operating as desired. The Chemistry Lab is also responsible for reviewing the data periodically and notifying Engineering when a problem may exist.

Response – If the analysis concludes that there may be an issue with a transformer, an SAP-PM notification shall be generated by anyone associated with the analysis. The notifications will then be reviewed and considered during the next applicable ECA Process Meeting. If immediate actions are required, those responsible for the analysis are also responsible for taking the appropriate timely actions with the Operations Organizations. Immediate actions will also require that a notification/work order be generated to track history and cost.

PSC DOCKET NO. 13-115
DELAWARE PUBLIC SERVICE COMMISSION STAFF
FOLLOW UP SET OF RELIABILITY DATA REQUESTS
TO DELMARVA POWER & LIGHT COMPANY

Question No.: PSC-REL-8

Please refer to AG-REL-3 Attachment A and Attachment B.

(a) Please explain what distinguishes a project that the company identifies as non-REP (Attachment B) versus REP (Attachment A).
(b) Please explain how the company's project identification, planning, selection, and budgeting processes differ for non-REP versus REP projects.
(c) Please explain whether any of the REP projects shown for (a) 2012 and (b) 2013 were required to maintain reliability at the levels as measured by Delaware SAIDI in the 2008-2011 time period
(d) If 2012 non-REP projects were completed in 2012 but the 2012 REP projects had been delayed for one year, what effect would it have had on the ability of the company to maintain system reliability for Delmarva Delaware customers at historical 2008-2011 SAIDI levels?
(e) Please explain how Delmarva priority-ranks the potential projects within each of the programs in the REP (e.g., priority feeds, URD).
(f) For each project on Attachment A and Attachment B, please provide a paragraph containing a more detailed description beyond the Short Description shown in the spreadsheets.

RESPONSE:

a. The REP is a way to combine the efforts into one program that discuss the commitment that the Company is making to continuously improve its reliability performance. The REP is an integral part of the Company's overall expansion-related efforts. REP work is identified based on the following work criteria, Priority Feeder Upgrades, Underground Residential Distribution Cable Upgrades (URD), Distribution Automation, Feeder Reliability Improvements, Conversions, Substation Reliability Improvements, Feeder Load Relief. Non-REP projects are comprised of all other work.

b. Reliability budget estimates are developed in the following manner:

1. Emergency work - the estimates are based on historical trends for similar activities.

2. Priority feeder and other Commission ordered activities - the budget is based on the amount of work ordered by the Commission and the average cost of performing the work.

3. Infrastructure replacement and upgrades – the budget is based on the level of activity projected to be performed over the five year period and either average historical costs or standard estimating units for each individual activity.

Throughout the year, if changes to the level of work are identified, these changes are discussed and approved at monthly budget coordination meeting. However, the budget is not modified.

c. All of Delmarva Power's reliability programs are designed to support the objective to maintain a minimum (and improve upon wherever possible) performance level of 295 minutes as measured by the System Average Interruption Duration Index (SAIDI) in accordance with paragraph 4.3 of the Electric Service Reliability and Quality Standards set forth in Regulation Docket No. 50.

d. Both REP and Non-REP projects can change from a timing and schedule standpoint. Delmarva maintains its performance and will complete all work necessary to maintain system reliability. The ability to maintain system reliability is dependent on the total work performed and not any one project. Therefore, an analysis that looks at the impact of delaying an individual project has not been performed.

Each of these categories is managed by distinct groups that plan and schedule their work to meet the timeline established when the budget was developed. For example, a project that is necessary to be in service prior to the beginning of the warm weather season will be engineered in a way that will allow sufficient time to be constructed prior to July 1. Vegetation management is planned to inspect and trim the overhead system on a two year schedule. Therefore each year half of the system is trimmed. Load growth is planned by the System planning group. They base their plans on historical load growth and prospective new growth within each substation geographic area. Feeder improvements and URD cable replacement are based on historical reliability performance of individual feeders and, like priority feeders, they are inspected and corrective actions identified. Distribution automation plans are developed based on historical reliability performance within an area and identification of feeder groups that can be combined to form an automation plan for load transfers.

e. The priorities for performing each project are based on available resources to design the projects, coordination with other projects that have fixed completion dates and permitting requirements. These projects are scheduled to be performed during the year and schedules can change to accommodate other projects that need to be completed by specific dates, such as customer connections or load projects needed prior to high load periods.

f. See PSC-REL-8 Attachments A and B.

Respondent: Michael W. Maxwell

DE 13-115
PSC-REL-8 Attachment A

	WBS	Short Description	Long Desciption
PRI FDR	UDLBRM4MF	Millsboro - Priority Circuit Improvement (UDLBRM4MF)	Install, remove, replace reclosers, switches, guards, and other equipment deemed necessary on the worst performing feeder circuits in Millsboro District, to improve and maintain continued safe and reliable operation.
	UDLNRM4CF	Priority Feeder Improvement - CHRISTIANA (UDLNRM4CF)	Install, remove, replace reclosers, switches, guards, and other equipment deemed necessary on the worst performing feeder circuits in Centreville District, to improve and maintain continued safe and reliable operation.
URD	UDLBRM4MC	Millsboro - Replace Deteriorated URD Cable (UDLBRM4MC)	Capital work necessary to replace underground cables due to failures.
	UDLBRM4MD	Millsboro Planned URD Cable Replacement (UDLBRM4MD)	Capital work necessary to maintain and replace the underground cables in subdivisions due to multiple failures.
	UDLNRM4CC	Replace Detoriated URD Cable - Christiana (UDLNRM4CC)	Capital work necessary to replace underground cables due to failures.
	UDLNRM4CD	Planned URD Cable Replacement - Christiana (UDLNRM4CD)	Capital work necessary to maintain and replace the underground cables in subdivisions due to multiple failures.
DA	UDLBRDA1D		Capital work necessary to install and utilize distribution automation.
	UDSBRDA1D	Substation Distribution Automation Bay - DE (UDSBRDA1D)	Substation Distribution Automation Projects in Bay Region - Delaware
	UOIBRASRD	Install ASR Computer: Bay DE (UOIBRASRD)	
	UDLNRDA1C	Distribution Automation: Christiana District (UDLNRDA1C)	Distribution automation work in the Christiana District
	UDSNRD8MD	Scada/RTU Upgrade NC DE Dist Sub (UDSNRD8MD)	SCADA and RTU equipment is obsolete and needs to be upgraded and replaced: Christiana A&B; Edge Moor 69kV; Harmony; Brookside; Glasgow; Milltown; Naamans; New Castle; Point Breeze; Talleyville; W.Wilmington
	UDSNRDA1C	Christiana Sub Distribution Automation (UDSNRDA1C)	Replace Identified Feeder Relays with SEL451 Front Line and SEL551 Backup on feeders either in Switchgear or in Control House as necessary. Also Install RTU/Communication Panel one in every substation being done having OrionLX, ethernet switches, GPS Clock and a Computer to communicate.
	UOINRASRD	Install ASR Computer: NC DE (UOINRASRD)	In identified New Castle Substations where Distribution Automation work is being completed, the ASR computer shall be installed.
	UORBOBR1M		
	UORBODA1M	MILLSBORO COMM WORK-RADIO INLINE EQUIP (UORBODA1M)	Project will provide for the installation of Silver Spring Networks eBridge radios in line equipment, including reclosers, switches, and capacitor banks in the Millsboro District.
	UORBORBSM	BBW Base Station - Install Millsboro (UORBORBSM)	Project will provide for the installation of Broadband Wireless base station radios and supporting hardware in the Millsboro district.
	UORBORBTM		
	UORBORCPM	Millsboro: Install Radio Control for Capacitor Controllers (UORBOR	Equipment in Millsboro District in order to establish communcations between the Capacitor Control and the centralized VAR management system.
	UORBORSSM	Millsboro Subscriber - BBW (UORBORSSM)	Project will provide for the installation of Broadband Wireless subscriber radios and supporting hardware in the Millsboro district substations.
	UORNOBR1C	CH Comm Work - Collector to Data Network (UORNOBR1C)	Project will provide for the installation of broadband wireless subscriber radios and supporting hardware to backhaul communications between remote DA and AMI applications and the backbone network in Christiana district.
	UORNODA1C	Christiana Comm Work - Install Radios in Line Equipment (UORNO	Project will provide for the installation of Silver Spring Networks eBridge radios in line equipment, including reclosers, switches, and capacitor banks in the Christiana District.
	UORNORBSC	BBW Base Station - Install Christiana (UORNORBSC)	Project will provide for the installation of Broadband Wireless base stations and supporting hardware in the Christiana district substations.
	UORNORDTC		
	UORNORCPC		
	UORNORSSC	Christiana Subscriber - BBW (UORNORSSC)	Project will provide for the installation of Broadband Wireless subscriber radios and supporting hardware in the Christiana district substations.
	UDLBRM63M	MI FEEDER RELIABILITY IMPROVEMNT (UDLBRM63M)	Capital work necessary to improve Reliability in Millsboro District
	UDLNRM63C	CHRISTIANA FEEDER RELIABILITY IMPROVEMNT (UDLNRM63	Capital work necessary to improve Reliability in Centreville District
	UDSBRD9SF	Millsboro - Replace T1 (UDSBRD9SF)	1. Remove the existing 15 MVA transformer T2 2. Replace it with 69/25KV 40MVA Transformer with LTC 3. Remove the existing FL & BU relays and replace it with new SEL 487E as FL and SEL 551 as BU relays 4. Add Orion-LX, Ethernet switch and GPS clock 5. New foundation and new Oil containment required 6. Assembly and testing to be done by Transformer manufacturer 7. Assume first 30% progress payment of $360k is made in 2012.
	UDSBRD9SG	North Seaford - Replace T2 & T3 with One Transformer (UDSBRD9	Replace transformers T2 & T3 with one new 28MVA, 69/12kV transformer. Replace two existing mains and tie breaker with two new feeder breakers, Install new 69kV breaker controls, new transformer protection, and new feeder protection. Replace 12kV box structure.

DE 13-115
PSC-REL-8 Attachment A

WBS	Short Description	Long Desciption
UDSBRD9SJ		
UDSBRD9SL		
UDSBRM61D		
UDSNRD8KD		
UDSNRD9KA	Milford Crossroads Substation 12kV Switchgear Replacement (UDS	Replace Switchgear #1 and #2 Install control house, control enclosure, or add additional compartments onto switchgear to house all relay and control equipment.
UDSNRD9KB	Bear Substation 12kV Switchgear Replacement (UDSNRD9KB)	Replace Switchgear #1 and #2 Remove bus duct bus tie and replace with underground cable Add main breakers to both switchgear line-ups Install controll house to house all control and relay equipment
UDSNRD9KC		
UDSNRD9KD		
UDSNRD9KE		
UDSNRD9KF		
UDSNRD9KG		
UDSNRD9KH		
UDSNRD9KI		
UDSNRM61D	Comprehensive Reliability Impvts: Dist Subs NC DE (UDSNRM61D	This WBS includes the switchgear projects Darley, Silverside and Point Breeze started in 2012, which will finish Jan-March of 2012.
UDLBRM8BA	Greenwood: 4-25kV Conversion (UDLBRM8BA)	Convert Greenwood feeder DE0558 from 4kV to 25kV, and replace/ upgrade all the deteriorated hardware.
UDLBRM8BB	Wyoming - Convert to 25kV Circuit 2233 (Phase II) (UDLBRM8BB)	Convert Wyoming feeder DE0513 from 4kV to 25KV, and replace/ upgrade all the deteriorated hardware.

LOAD

UDLBLFP2		
UDLBLM7M	Future Projects Dist Line Millsboro (UDLBLM7M)	
UDLBLM7M		
UDLBLM7M.1		
UDLBLM7M.13		
UDLBLM7M.2		
UDLBLM7M.6		
UDLBLMG1		
UDSBLFP1		
UDLBLMW2		
UDSBLM72A	Clayton - Replace T3 (UDSBLM72A)	Replace T3 transformer at Clayton Substation with a 3.2 MVA, three-phase transformer. Add voltage regulators and low side recloser. Plan to build new foundation with oil containment near the existing transformer along with foundations for new recloser and regulators. New transformer will still be protected by high-side fuses. Plan to build all ahead of time then do a short overnight outage to transfer load to the new transformer. Replace the T2 low side disconnect switch and 500 MCM bus. Rating of T2 low side terminal to be 34 MVA (787 A) Normal Rating.
UDSBLM73A	Millsboro T2 Upgrade Disconnect Switch (UDSBLM73A)	
UDSBLM73B		
UDSBLM73C	Harbeson Substation Upgrade T1 (UDSBLM73C)	Replace Harbeson T1 with new 69-25kV 37MVA Transformer New transformer will be located on new foundation near 25kV structure. 69kV terminal will be designed to connect to new T1 high side switch with MOD. Installation will include removing 25kV regulators, installing new 25kV low side circuit breaker for and new tie circuit breaker for 25kV bus.T1, disconnect switches for T1 low side breaker, low side disconnect for T1, Installation will include new SEL 451s for breaker control for CBs 3140 and 3190 and an SEL 487E and SEL 451 for transformer differential protection.
UDSBLM76A	Cedar Neck Substation: Install 2nd 69/12kV Transformer (UDSBLM	Create a 5 position 69kV ring bus (ultimate 6 position). Add one 69/12kV 40 MVA transformer, one 1200 A 12kV feeder, two 2000A main breakers, one 2000A 12kV tie breaker with associated protection and controls. Add one additional 69kV line terminal and mobile transformer position, with space for a future 69kV, two stage capacitor bank. Add control house addition and upgrade existing relays on transformer T1 and existing feeders.
UDSBLM7D		
UDSBLMG2		
UDLNLCBC2		
UDLNLM7C	CHRISTIANA FEEDER LOAD RELIEF (UDLNLM7C)	Install 1200 & 2400kvar cap banks at various locations as directed by System Planning
UDLNLM7C	CHRISTIANA FEEDER LOAD RELIEF (UDLNLM7C)	
UDLNLM7C.10		
UDLNLM7C.11		
UDLNLM7C.17		
UDLNLM7C.2		
UDLNLM7C.21		
UDSNLM72A	W.Wilmington Sub Bus & Bkr Upgrade (UDSNLM72A)	Install two(2)- 3000 amp 12kV main breakers for each T1 & T2 transformer; redesign and upgrade primary to allow one transformer to support the full load of the substation in case of failure of the other transformer; upgrade protection and control to current standards.
UDSNLM7D		

DE 13-115
PSC-REL-8 Attachment B

Items	Project ID	FERC Area	Budget Category	Long Description
Bay DE - Replace MV Streetlights (UDLBCMVD)	UDLBCMVD	Distribution	Customer Driven	Remove older, less efficient, Mercury-filled streetlights with higher efficiency high-pressure Sodium units.
Bay DE Transm Line Upgrades for Solar (UDLBCSOLD)	UDLBCSOLD	Distribution	Customer Driven	
Bay Region Delaware Substation Work for Solar Project s (U	UDSBCSOLD	Distribution	Customer Driven	
Christiana - Facility Relocations (UDLNCS3C)	UDLNCS3C	Distribution	Customer Driven	'Christiana District - Facility Relocations
Christiana - Highway Relocations (UDLNCH0C)	UDLNCH0C	Distribution	Customer Driven	'Christiana District - Highway Relocations
Christiana - New Services & St Lights (UDLNCS1C)	UDLNCS1C	Distribution	Customer Driven	Christiana Operations Blanket Project to house all the labor/contractor/material for the following type of new customer electrical services: New Residential Service New Commercial/Industrial Service New Street Lighting Service Upgrades to Existing Customer Service
Christiana - Residential Infrastructure (UDLNCS2C)	UDLNCS2C	Distribution	Customer Driven	Christiana District - Residential Infrastructure
DE - NEW LOAD ACCRUALS & EMERGENCY (UDLNCACF	UDLNCACRD	Distribution	Customer Driven	
DPL Reg: New Load Accuals & Emerg (UDLNCACCR)	UDLNCACCR	Distribution	Customer Driven	
Mercury Vapor St Lights Replace - NC DE (UDLNCMVD)	UDLNCMVD	Distribution	Customer Driven	Mercury Vapor St Lights Replace - NC DE
Meter Blanket - AMI - DPL (UDLNCMR2)	UDLNCMR2	Distribution	Customer Driven	
Meter Blanket - AMI NC DE (UDLNCMR2D)	UDLNCMR2D	Distribution	Customer Driven	
Meter Blanket - New Castle Reg (UDLNCMR1)	UDLNCMR1	Distribution	Customer Driven	
MI- Facility Relocations (UDLBCS3M)	UDLBCS3M	Distribution	Customer Driven	Relocate DPL aerial and underground electric facilities per customer request in Kent and Sussex Counties, DE
MI- New Services & St Lights (UDLBCS1M)	UDLBCS1M	Distribution	Customer Driven	Install new Services and Steeet Lights in Millsboro District - Kent and Sussex County, DE
Millsboro - Highway Relocations (UDLBCH0M)	UDLBCH0M	Distribution	Customer Driven	Relocate DPL facilities for DelDOT road projects in Kent and Sussex Counties, DE
MI-Residential Infrastructure (UDLBCS2M)	UDLBCS2M	Distribution	Customer Driven	Install DPL backbone electric facilities in residential developments in Kent and Sussex Counties, DE
Bear DE0752: Reconductor the Getaway (UDLNLM7C.11)	UDLNLM7C.11	Distribution	Load Driven	
[redacted]				
Underbuilt Distribution Rebuild: Bay DE (UDLBPN7DD)	UDLBPN7DD	Distribution	PJM/RTEP	Rebuild underbuilt distribution facilities in conjunction with transmission upgrade projects in Bay region of DE
[redacted]				
CHRISTIANA FEEDER LOAD RELIEF (UDLNLM7C)	UDLNLM7C	Distribution	Load Driven	
CHRISTIANA - DISTRIBUTION VAR CORRECTION (UDLNI	UDLNLM7C.10	Distribution	Load Driven	
MERMAID DE0745 R/C GETAWAY & ADD RECLOSER (UC	UDLNLM7C.17	Distribution	Load Driven	
Install Dist. Regulators- Fdr Load Relief (UDLNLM7C.2)	UDLNLM7C.2	Distribution	Load Driven	
Distribution Line Work for Sub Expansion (UDLNPBC1)	UDLNPBC1	Distribution	PJM/RTEP	Distribution Line Work for Sub Expansion
Brandwine to Edgemoor Distribution Underbuild of the 13804	UDLNPBC2	Distribution	PJM/RTEP	
[redacted]				
Cedar Neck Substation: Install 2nd 69/12kV Transformer (UC	UDSBLM76A	Distribution	Load Driven	
Future Projects Bay Region Distribution Delaware (UDSBLM	UDSBLM7D	Distribution	Load Driven	
Magnolia Area 230/25kV Substation - Build New Substation (	UDSBLMG2	Distribution	Load Driven	
Midway Substation - Install New Transformer (UDSBLMW1)	UDSBLMW1	Distribution	Load Driven	
[redacted]				
NC-DE Future projects (UDSNLM7D)	UDSNLM7D	Distribution	Load Driven	
12kV ACB Refurbishment New Castle (UDSNRD9K)	UDSNRD9K	Distribution	Reliability Driven	
BAYDERemoval & Salvage Capitalized Equip (UDLBMS5D)	UDLBMS5D	Distribution	Reliability Driven	Bay Region Delaware: Millsboro District Office Cost to scrap retired poles, transformers, etc. Cost of salvage related to the sale of transformers.
Bay DE Reg: Salvage Scrap Wire/Cable (UDLBOSV5DE)	UDLBOSV5DE	Distribution	Reliability Driven	Bay Region Delaware: Millsboro District Office Cost to scrap wire/cable.
BAY-DE - Accural for Reliability (UDLBRACRD)	UDLBRACRD	Distribution	Reliability Driven	
Distribution Automation - Bay DE (UDLBRDA1D)	UDLBRDA1D	Distribution	Reliability Driven	
Emergency Restoration Blanket - Millsboro (UDLBRM3M1)	UDLBRM3M1	Distribution	Reliability Driven	Funds necessary for the emergency restoration of customers.
Millsboro Misc. Distribution Improvement Blanket (UDLBRM4	UDLBRM4MA	Distribution	Reliability Driven	Capital work necessary to maintain electric service in the Millsboro District. Improvement of equipment replacement due to load and/or rearrangement requiring design
[redacted]				
Millsboro District - Distribution Pole Replacement (UDLBRM4	UDLBRM4ME	Distribution	Reliability Driven	
[redacted]				
Millsboro Avian Protection Improvement (UDLBRM4MH)	UDLBRM4MH	Distribution	Reliability Driven	
Millsboro District - Recloser Replacement (UDLBRM4MJ)	UDLBRM4MJ	Distribution	Reliability Driven	Capital work necessary to replace reclosers to provide for a properly operating distribution system.
Customer Reliability Improvement - Millsboro (UDLBRM4MM	UDLBRM4MM	Distribution	Reliability Driven	Capital work needed to complete projects aimed at specific customer reliability focused intiatives
Millsboro - Padmount Transformer Replacements (UDLBRM4	UDLBRM4MO	Distribution	Reliability Driven	
Millsboro - Upgrades for Multi Device Operations (UDLBRM4	UDLBRM4MQ	Distribution	Reliability Driven	
Bishop Substation - Lines Upgrade - DE (UDLBRM4RC)	UDLBRM4RC	Distribution	Reliability Driven	Upgrade 4/0 CU from Bishop to Selbyville with 954-AAC for new Bishop circuit. Funds needed for 2012 carry over into 2013
NERC Line Upgrades: Dist Lines Bay DE 2 (UDLBRM5MD)	UDLBRM5MD	Distribution	Reliability Driven	
IR: Millsboro - Replace Deter Dist Line Switches (UDLBRM5I	UDLBRM5MZ	Distribution	Reliability Driven	
NERC Line Upgrades: Dist Lines Bay DE 1 (UDLBRM5ND)	UDLBRM5ND	Distribution	Reliability Driven	
[redacted]				
Distribution Transformer Retirements DE (UDLNMS3D)	UDLNMS3D	Distribution	Reliability Driven	

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Items	Project ID	FERC Area	Budget Category	Long Description
NC DE Removal & Salvage Capitalized Equipment (UDLNM	UDLNMS5D	Distribution	Reliability Driven	New Castle Region Delaware Christiana District Office Cost to scrap retired poles, transformers, etc. Cost of salvage related to the sale of transformers.
NC DE Reg: Salvage Scrap Wire/Cable (UDLNOSV5D)	UDLNOSV5D	Distribution	Reliability Driven	
NC-DE - Accrual for Reliability (UDLNRACRD)	UDLNRACRD	Distribution	Reliability Driven	
Emergency Restoration Blanket-Christiana (UDLNRM3C1)	UDLNRM3C1	Distribution	Reliability Driven	Capital work needed to maintain or restore electric service
Misc. Improvements Blanket - Christiana (UDLNRM4CA)	UDLNRM4CA	Distribution	Reliability Driven	Capital work necessary to maintain electric service.
Christiana District - Distrib Pole Repl/Reinf (UDLNRM4CE)	UDLNRM4CE	Distribution	Reliability Driven	Replace and/or reinforce failing poles in the Christiana District
Christiana Avian Protection (UDLNRM4CH)	UDLNRM4CH	Distribution	Reliability Driven	
Replace Line Reclosers - Christiana (UDLNRM4CJ)	UDLNRM4CJ	Distribution	Reliability Driven	Replace line reclosers periodically to provide for a properly operating distribution system.
Customer Reliability Improvements - Christiana (UDLNRM4C	UDLNRM4CM	Distribution	Reliability Driven	Address customer concerns about recent reliability issues. Install fuses, reclosers, trim trees, reconductor, etc.
Christiana: Padmount Transformer Replacements (UDLNRM	UDLNRM4CO	Distribution	Reliability Driven	
Christiana: Upgrades for Multi Device Operations (UDLNRM4	UDLNRM4CQ	Distribution	Reliability Driven	
Wilmington Network Upgrade (UDLNRM4CR)	UDLNRM4CR	Distribution	Reliability Driven	Upgrade the aerial sections of the Wilmington Network by replacing poles, wires and adding distribution transformers as needed.
Install tree wire/spacer cable - Christiana (UDLNRM4CU)	UDLNRM4CU	Distribution	Reliability Driven	
NC Region : Priority Fdr Rebuild (UDLNRM4K)	UDLNRM4K	Distribution	Reliability Driven	
NERC Line Upgrades: Dist Lines NC DE 2 (UDLNRM4MD)	UDLNRM4MD	Distribution	Reliability Driven	
Rogers Road Sub. Convert 4kV to 12kV (UDLNRM5BA)	UDLNRM5BA	Distribution	Reliability Driven	
EDGEMOOR TO GM 12kV Underbuild (UDLNRM5BC.1)	UDLNRM5BC.1	Distribution	Reliability Driven	
NERC Line Upgrades: Dist Lines NC DE 1 (UDLNRM5ND)	UDLNRM5ND	Distribution	Reliability Driven	
Christiana Substation Feeder relocation (UDLNRM5SC)	UDLNRM5SC	Distribution	Reliability Driven	Install new conduit and manhole system to relocate 27 distribution feeders serving the City of Wilmington
DE0217 Reconductor (UDLNRM5SD)	UDLNRM5SD	Distribution	Reliability Driven	Reconductor circuit DE0217, which serves as the back-up to Riverside Hospital. Circuit DE0217 has experienced numerous failures in recent months and has had to be taken out of service until the primary distribution cable can be upgraded
Cable Replacement for New Substation Switch Gears (UDLN	UDLNRM5SE	Distribution	Reliability Driven	REPLACE CABLE FROM BREAKERS TO FIRST MANHOLE FOR ALL FEEDERS ON NEW SUBSTATION SWITCHGEARS.
Rebuild OH Rear Lot Dist Sys-Christiana (UDLNRM8SE)	UDLNRM8SE	Distribution	Reliability Driven	
Churchmans - Replace Reclosers (UDLNRM8SH)	UDLNRM8SH	Distribution	Reliability Driven	
Wilmington Steel Poles Replacement (UDLNRM9SB)	UDLNRM9SB	Distribution	Reliability Driven	Replace deteriorating steel poles along 4th Street in Wilmington.
MILLTOWN RD - MOVE DE0640 FROM T1 TO T3 (UDLNR	UDLNRMT1	Distribution	Reliability Driven	
Bay Dist. Sub. Emergency - DE (UDSBRD71D)	UDSBRD71D	Distribution	Reliability Driven	
Bay Dist Sub Planned Impvts - DE (UDSBRD8AD)	UDSBRD8AD	Distribution	Reliability Driven	
Bay Dist Sub Relay Impvts DE (UDSBRD8BD)	UDSBRD8BD	Distribution	Reliability Driven	This project is a blanket that does not have a defined scope yet. This blanket is intended for very simple misc. relay upgrades that may need to be completed each year.
Laurel - DPU Replacement (UDSBRD8DD)	UDSBRD8DD	Distribution	Reliability Driven	Replace the existing DPU relays with SEL451/SEL551 feeder protection/control packages at Laurel substation. Replace DPU relay on feeder 506 and remove old DPU equipment. Replace CB 1. An Orion-LX and a GPS clock will be added to replace the existing SEL-2030 which are included in this estimate.
Bay Dist. Subst. Battery & Charger Replacement - Delaware	UDSBRD8ED	Distribution	Reliability Driven	Replace Bay Distribution Substation Batteries and Chargers in two Delaware locations which have deteriorated, tested poorly or have reached end of life.
Bay Dist. Subst. Bushing Repl. - DE (UDSBRD8FD)	UDSBRD8FD	Distribution	Reliability Driven	2013-2017: Replace bushing sets on 3 distribution transformers in 2013 and then 2 per year through 2017 within the Bay Region in Delaware that have deteriorated or tested poorly.
Bay Distribuition DE - PHI Spare Transformers (UDSBRD8G	UDSBRD8G	Distribution	Reliability Driven	Purchase spare distribution transformers for Bay Region. Included in estimate are following: 1. Purchase of 138/12kV, 37MVA transformer, ISD June 2013, including foundation construction, offloading costs, testing, assembly, engineering and consulting costs, and total cost of transformer 2. Purchase of 69/12kV, 37MVA transformer, ISD June 2013, including foundation construction, offloading costs, testing, assembly, engineering and consulting costs, and total cost of transformer 3. Purchase of 69/25kV, 37MVA transformer, ISD June 2014, including foundation construction, offloading costs, testing, assembly, engineering and consulting costs, and total cost of transformer
Bay DE - Purchase Mobile Transformer (UDSBRD8G2D)	UDSBRD8G2D	Distribution	Reliability Driven	
Bay Region DE purchase 138/25kV Mobile Unit (UDSBRD8G	UDSBRD8G3D	Distribution	Reliability Driven	
Bay Region DE 138x69kV / 25kV 30MVA Mobile Unit (UDSB	UDSBRD8G4D	Distribution	Reliability Driven	
Bay-Replace Dist. Sub. Control House Roofs (DE) (UDSBRD	UDSBRD8ID	Distribution	Reliability Driven	
Upgrade SCADA/RTU Capability - DE (UDSBRD8MD)	UDSBRD8MD	Distribution	Reliability Driven	
Surplus Dist Sub Equipment Retirements-DE (UDSBRD8PD)	UDSBRD8PD	Distribution	Reliability Driven	
Greenwood Substation - Retire / Remove 4KV (UDSBRD8RE	UDSBRD8RB	Distribution	Reliability Driven	
Wyoming Substation - Retire (UDSBRD8RG)	UDSBRD8RG	Distribution	Reliability Driven	
Physical Security - Bay - DE Dist Sub (UDSBRD8VD)	UDSBRD8VD	Distribution	Reliability Driven	Since no scope was available from the Security department and no defintive plans for DA in Delaware, this estimate assumes one installation per year of a physical security system consisting of key card locks on the substation control house doors, a key card lock and motorized sliding gate on one fence gate, and a Future Sentry perimeter security system with all associated sensors and solar power option.
Replace Deteriorated Distribution Breakers-DE (UDSBRD9D	UDSBRD9DD	Distribution	Reliability Driven	2013-2017 - Replace ten distribution oil breakers per year through 2015, then replace twenty per year for years 2016 and 2017. Estimates are split evenly between Maryland and Delaware because deteriorated breakers cannot be determined until testing. For budgeting, assumed all breakers are 27kV, 1200A.
Replace aging transformers - Bay DE (UDSBRD9GD)	UDSBRD9GD	Distribution	Reliability Driven	

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Items	Project ID	FERC Area	Budget Category	Long Description
North Seaford - Replace T2 & T3 with One Transformer (UDS	UDSBRD9SG	Distribution	Reliability Driven	
Sussex - Replace T2 Transformer (UDSBRD9SX1)	UDSBRD9SX1	Distribution	Reliability Driven	
Bay Replace Deteriorated Dist. Sub. Structures - DE (UDSBF	UDSBRD9YD	Distribution	Reliability Driven	
Bay Region Repl Deteriorated Sub Dist Sws - Delaware (UD	UDSBRD9ZD	Distribution	Reliability Driven	
Bay: DE Dist Sub Comprehensive Reliability Impvts (UDSBR	UDSBRM61D	Distribution	Reliability Driven	
New Castle Substation Emergency (UDSNRD71)	UDSNRD71	Distribution	Reliability Driven	Funds set aside for contingencies across distribution substations in Delaware
NC - DE SUBSTATION EMERGENCY - DIST (UDSNRD71D	UDSNRD71D	Distribution	Reliability Driven	Funds set aside for contingencies across distribution substations in Delaware
Substation Planned Improvements - New Castle (UDSNRD8	UDSNRD8A	Distribution	Reliability Driven	
NC - DE Substation Planned Improvements (UDSNRD8AD)	UDSNRD8AD	Distribution	Reliability Driven	Blanket project - Planned capital improvements including control house upgrades, roof replacements, and cable troughs, etc in Delaware.
NC DE Dist Misc Relay Blanket (UDSNRD8BD)	UDSNRD8BD	Distribution	Reliability Driven	
NC DE: Dist Sub Battery & Charger Replacement (UDSNRD	UDSNRD8ED	Distribution	Reliability Driven	
NC DE: DIST SUBST BUSHING REPLACEMENT (UDSNRD	UDSNRD8FD	Distribution	Reliability Driven	Replace bushing sets on transformers, in which the bushings have deteriorated or have not met testing specifications. Recommend replacing Type "U" or as identified by Maintenance testing data. Estimate based on 4 projects per year for 2013-2014, then 3 projects per year 2015-2017.
New Castle PHI Spare Transformers (UDSNRD8G)	UDSNRD8G	Distribution	Reliability Driven	Purchase PHI Spare XFMRS for New Castle region: 69/34 kV, 56 MVA (2013 - June) 230/34 kV 100MVA (2014 - May) 138/34 kV 100MVA (2015 - May)
New Castle - Purchase 138/69 -12 kV Mobile XFMRs (UDSN	UDSNRD8G1	Distribution	Reliability Driven	Purchase 138/12.47 kV and 69/12.47 kV Mobile XFMRs 30-40 MVA for New Castle region Progress payment of approximately $1,200,000 planned to be made in 2012
Christiana Substation. Upgrade T-2 XFMR (UDSNRD8GD)	UDSNRD8GD	Distribution	Reliability Driven	Purchase Spare XFMR for Christiana Substation Transformer is on order with expected delivery and installation in Nov.- Dec 2012
NC Reg: 15kv Switchgear Improvements (UDSNRD8K)	UDSNRD8K	Distribution	Reliability Driven	
DPL DE - Switchgear replacements (UDSNRD8KD)	UDSNRD8KD	Distribution	Reliability Driven	
NC Reg: Misc Dist Sub Equipment Retirement (UDSNRD8P)	UDSNRD8P	Distribution	Reliability Driven	
IR NC DE: Dist Sub Misc Equip Retire (UDSNRD8PD)	UDSNRD8PD	Distribution	Reliability Driven	
North Wilmington Sub. Cleanup and retire (UDSNRD8RA)	UDSNRD8RA	Distribution	Reliability Driven	Cleanup and retire Substation. Return property to Green field condition All equipment and cables are removed from the property Control house to be demolished and foundations to be removed.
Tenth Street Substation - Cleanup and retire (UDSNRD8RC)	UDSNRD8RC	Distribution	Reliability Driven	
CHURCHMAN'S RECLOSER REMOVAL (UDSNRD8SA)	UDSNRD8SA	Distribution	Reliability Driven	
SILVERBROOK SUBST - FAILED T-3 REPLMNT (UDSNRD	UDSNRD8SE	Distribution	Reliability Driven	
Chapel Street Substation - Resupply Station Service (UDSNI	UDSNRD8SI	Distribution	Reliability Driven	Installation of Physical Security Systems at Identified Distribution Substations. Above and Beyond Security scope includes: 1. Card Access and Exit Readers on gates and Control House doors 2. Alarms 3. Future Sentry camera systems with Solar Power solution.
NERC Physical Security - NC-DE Dist Sub (UDSNRD8VD)	UDSNRD8VD	Distribution	Reliability Driven	
IR Roger Road Substation. Clean up and retire (UDSNRD9A	UDSNRD9A	Distribution	Reliability Driven	
NC DE: Breaker Replacement Dist Sub (UDSNRD9DD)	UDSNRD9DD	Distribution	Reliability Driven	Replace deteriorated distribution breakers: West Substation, others yet to be planned. ~16 breakers per year until 2015.
IR: NC DE DISTR SUB REPL/UPGRADE PTS (UDSNRD9FI	UDSNRD9FD	Distribution	Reliability Driven	Replace Deteriorated distribution potential transformers in New Castle Region in Delaware. These Pt's are low or leaking oil
Replace Deteriorated Distr. XFMRs DE (UDSNRD9G1)	UDSNRD9G1	Distribution	Reliability Driven	
NC DE SUBS: Replace PCB 34.5kV Cap Banks (UDSNRD9I	UDSNRD9HD	Distribution	Reliability Driven	Replace entire capacitor bank at Darley Substation
Naamans Substation 12kV Switchgear Replacement (UDSNI	UDSNRD9KC	Distribution	Reliability Driven	
Mermaid Substation - 12kV Switchgear Replacement (UDSN	UDSNRD9KD	Distribution	Reliability Driven	
West Wilmington Substation 12kV Switchgear Replacement (	UDSNRD9KE	Distribution	Reliability Driven	
Churchmans Substation 12kV Switchgear Replacement (UD	UDSNRD9KF	Distribution	Reliability Driven	
Milltown Substation 12kV Switchgear Replacement (UDSNRI	UDSNRD9KG	Distribution	Reliability Driven	
Sunset Lake Substation 12kV Switchgear Replacement (UD	UDSNRD9KH	Distribution	Reliability Driven	
Talleyville Substation 12kV Switchgear Replacement (UDSN	UDSNRD9KI	Distribution	Reliability Driven	
Edge Moor Sub- Upgrade 12kV Main Breakers (UDSNRD9S	UDSNRD9SE	Distribution	Reliability Driven	Upgrade the 7 seven(7) obsolete 1950's vintage high current, high fault interrupting air blast General Electric 4000 amp, 60KA 14.4kV GE air blast circuit breakers These breakers are located at Edge Moor 12kV yard and now supply only the Calpine Edge Moor plant. Calpine will be reimbursing PHI partially on 5 breakers in 2012 in accordance with the agreement.
Brookside Sub - Upgrade T-2 (UDSNRD9SH)	UDSNRD9SH	Distribution	Reliability Driven	Replace Brookside T2 with a new 34/12kV 20 MVA transformer. The new arrangement will be located within the Brookside Substation. Include a high side 34kV breaker for T2. The new arrangement will include 12kV breakers that can accommodate 1 future circuit and a mobile position. T2 should be placed in order to allow for installation of a second feeder from T2 in the future. Also provide necessary protection equipment.
Milford Crossroads Sub. Replace T-2 (UDSNRD9SJ)	UDSNRD9SJ	Distribution	Reliability Driven	Replace Milford Crossroads T-2 Transformer with a new 34/12 kV 20MVA transformer Direct Replacement Transformer is on order now and 3 progress payments expected to be made in 2012
West Sub. Replace T-2 69/34 kV 18 MVA Transformer (UDS	UDSNRD9SK	Distribution	Reliability Driven	Replace West Substation T-2 Transformer with a new 69/34.5 kV 30/40/50 MVA transformer
West Sub. Replace T-5 69/34 kV transformer (UDSNRD9SL	UDSNRD9SL	Distribution	Reliability Driven	
Kiamensi T2: Replace Transformer (UDSNRD9SM)	UDSNRD9SM	Distribution	Reliability Driven	
Talleyville T2: Replace Transformer (UDSNRD9SN)	UDSNRD9SN	Distribution	Reliability Driven	
IR: NC Repl Deter Structures Dist Subs (UDSNRD9Y)	UDSNRD9Y	Distribution	Reliability Driven	
IR: NC-DE Repl Deter Structures Dist Subs (UDSNRD9YD)	UDSNRD9YD	Distribution	Reliability Driven	
NC DE Repl Deter Switches Dist Sub (UDSNRD9ZD)	UDSNRD9ZD	Distribution	Reliability Driven	
UF NC Region: Distribution Automation (UDSNRDA1)	UDSNRDA1	Distribution	Reliability Driven	
Milltown: Move Feeder to 640 (UDSNRMT2)	UDSNRMT2	Distribution	Reliability Driven	

PSC DOCKET NO. 13-115
DELAWARE PUBLIC SERVICE COMMISSION STAFF
INITIAL SET OF COST OF SERVICE DATA REQUESTS
TO DELMARVA POWER & LIGHT COMPANY

Question No.: PSC-COS-29

Please refer to page 9, line 22 to page 10 line 1 of the Testimony of Elliott P. Tanos. Please provide (1) a definition and narrative explanation of the referenced weighted Class MDD and Customer NCP factors, describing the data used and all calculations employed in developing the weighted Class MDD and Customer NCP factors used in the COSS, (2) workpapers and supporting documentation showing the development of the weighted Class MDD and Customer NCP factors in the COSS, including workpapers and supporting documentation for all diversity and loss factors used, and (3) a list of all system locations where demand is measured by demand meters, i.e., customer, substation, etc., indicating the distribution level at which the meters measure demand, i.e., customer, line transformer, secondary, primary, sub-transmission and transmission. Calculation workpapers should be provided in electronic spreadsheet format with all formulae and macros intact.

RESPONSE:

1. The Class Maximum Diversified Demand (Class MDD) is the maximum hourly demand found for the customer class over the analysis period where the simultaneous demands of the class of customers is taken as a whole.

   The Customer Non-coincident Peak (NCP) is the sum of the individual maximum demands of the customers within a class on a customer-by-customer basis over the analysis period.

   Please see Schedule (EPT-1), page 18, lines 1-7 for the development of the weighted Class MDD and Customer NCP demand factors. Please also see the example below that shows the calculation of the DEMSEC allocation factor for the Residential class:

   Residential DEMSEC calculation:

   50% [Specific Class MDD/(Sum of applicable Customer Classes' MDD)] +
   50% [Specific Customer NCP/(Sum of applicable Classes' Customer NCP)]
   Residential DEMSEC = 50% [755,061 / 1,460,013] +
   50% [1,818,377 / 3,472,404]
   = 0.52041

2. Please see the response to part (1) above.
3. The information is not available in the form requested and would require significant original work to create.

Respondent: Elliott P. Tanos

PSC DOCKET NO. 13-115
ATTORNEY GENERAL OF THE STATE OF DELAWARE
FIRST SET OF COST OF SERVICE DATA REQUESTS
TO DELMARVA POWER & LIGHT COMPANY

Question No. : AG-COS-16: Load Research

a. Provide a listing of all Company jurisdictional rate classes which are not 100% demand metered, and thus had to be estimated through load research sampling.

b. Provide an overall numerical count of Company customers included within its load research sample.

c. In as much granular detail as available, provide a numerical count by (1) jurisdiction, (2) customer class, and (3) rate class, of Company customers included within its research sample.

d. Provide all workpapers and source documents supporting the Company's response in electronic form, with all spreadsheet links and formulas intact, source data used, and explain all assumptions and calculations used. To the extent the data requested is not available in the form requested, provide the information in the form that most closely matches what has been requested.

RESPONSE:

(a) The rate classes that did not have a majority of service points demand metered were the "R" Residential Service, "R-TOU" Residential Time of Use, and "R-TOU-ND" Residential Time of Use Non-Demand rate classes where the customers have electric heat are combined to form the DE Residential Space Heating cost of service class. The "R" Residential Service, "R-TOU" Residential Time of Use, and "R-TOU-ND" Residential Time of Use Non-Demand rate classes where the customers do not have electric heat are combined to form the DE Residential cost of service class. The sum of the customer maximum demands (NCDs), for each of these classes were determined from load research samples.

(b) The Company has ten independent samples for each profile class where two Delaware residential profile classes were involved in the calculation of the sum of the maximum referenced in this question. The total number of services in the two residential samples drawn was 277.

(c) The breakdown of the Company's Delaware residential profile samples used for the NCD is as follows:

Profile Class	(1) Jurisdiction	(2) Customer Class	(3) Rate Class	Sample Size
DEDRH	Delaware	Res Space Heating	R	157
DEDRS	Delaware	Residential	R	120

(d) Refer to the response to AG-COS- 19 part A. The cited attachment contains the sample sizes.

Respondent: Elliott P. Tanos

PSC DOCKET NO. 13-115
DELAWARE PUBLIC SERVICE COMMISSION STAFF
INITIAL SET OF COST OF SERVICE DATA REQUESTS
TO DELMARVA POWER & LIGHT COMPANY

Question No. : PSC-COS-22

Please refer to page 3, lines 8-11 of the Testimony of Elliott P. Tanos. Please (1) list all of the referenced initiatives that the Company has undertaken and reflected in the cost of service study and all initiatives undertaken but not reflected in the cost of service study and (2) for each initiative undertaken (both reflected and not reflected) explain in detail the Company's efforts.

RESPONSE:

Please see the attached agenda for the Cost of Service Workshop held on August 24, 2011, together with the description below summarizing the initiatives undertaken by the Company.

1. Load data for Delaware Residential Customers: Delaware specific load survey data has been used to estimate the Residential Class Non Coincident Demand measures used in the COSS in this proceeding.

2. Weather Normalized Sales and Revenues: The Company has developed weather normalized sales and revenues for each customer class that have been used in the COSS.

3. Analysis of System Losses: An updated analysis of system losses for Delmarva was conducted and the calculated loss factors have been used in the development of the demand measures applied in the COSS.

4. Service Line Analysis: The Company has estimated the applicable service line costs for the respective customer classes, which have been used to allocate the embedded costs contained in Account 369 – Service Lines.

5. Traffic Signal Service: As requested in the workshop, the Company has separated the Traffic Signal Service from the general Street Lighting Service in the COSS.

6. Geospatial Information System (GIS) use in COSS: The Company continued to use the GIS in the process of separating the distribution primary and secondary systems for COSS purposes.

7. Costs of Pull-offs for GST and GSP Customers: The Company's review found that most GST customers paid for the pull-off costs to Delmarva's connection point. The Company identified only two GST customers with approximately $70,000 of gross plant associated with pull-offs, and these lines were 69kV (transmission level). Regarding GSP customers: the costs for any overhead pull-offs would typically be small and it is considered impracticable to attempt this cost classification with respect to installed plant, the year of installation, and the corresponding reserve attributable to any such facilities.

8. Other Operating Revenue Allocations: the COSS reflects the Company's allocation of each component of other operating revenues, as shown on Schedule (EPT)-1, page 7.

9. Post Case Filing COSS updates: the Company has agreed to provide post case filing COSS updates for any material corrections.

10. COSS model availability and instructions: the Company has extended the invitation and remains available to provide instructions on the use of the cost of service model.

Respondent: Elliott P. Tanos

2011 Delmarva Power
Cost of Service Study Workshop Agenda
August 24, 2011
9:30 AM
Conference Room B
(DPSC Offices in Dover)

- **Load data for Delaware residential customers**
- **Weather normalized sales and revenues**
- **Load loss analysis**
- **Allocator for customer related items**
  - **Service drops**
  - **Meters**
  - **Installations on customer premises**
  - **Street lighting**
    - **Traffic signal service separation**
- **GIS use to functionalize plant**
- **Primary pulloffs**
- **Assigned plant to Rate GTS**
- **Other Operating Revenue allocations**
- **Test Year Adjustments in CCOSS**
- **Post Case Filing COSS Updates**
- **CCOSS model availability and instructions**

PSC DOCKET NO. 13-115
ATTORNEY GENERAL OF THE STATE OF DELAWARE
FIRST SET OF GENERAL DATA REQUESTS
TO DELMARVA POWER & LIGHT COMPANY

Question No. : AG-GEN-10

Re: statement in Santacecilia Direct, page 8, lines 21-23: "The revenues calculated for this and all the Rate-making Adjustments are contained in Schedule (MCS)-3." Provide all spreadsheets and supporting workpapers in electronic spreadsheet format with all links and formulas intact, source data used, and explain all assumptions and calculations used to develop the revenues calculated in Schedule MCS-3 and any rate-making adjustments that are a function of revenue. To the extent the data requested is not available in the form requested, provide the information in the form that most closely matches what has been requested.

RESPONSE:

Please see attached.

Respondent: Marlene C. Santacecilia

Pepco Holdings Inc. - Delmarva Power
Delaware Weather Corrected Sales & Revenues - COSS Rate Classes
30 Year Weather Correction
Year Ending December 2012

	COSS Rate Class							
	RES (1,2,6,7)	RSH (8,9)	GSSS (10,11,12,13,14)	GSSL (16)	GSP (17,18,26)	GST (20,40)	PSL* (21,25,30)	TOTAL
Delivered Sales(Kwh)	1,949,426,260	979,752,056	1,290,892,398	618,377,417	2,441,367,717	978,370,640	50,015,408	8,308,201,896
Booked Revenue								
Distribution *	$54,128,289	$21,236,193	$26,177,023	$6,237,578	$17,963,417	$208,594	$670,891	126,621,986
Transmission								
Generation (SOS)								
Total	$54,128,289	$21,236,193	$26,177,023	$6,237,578	$17,963,417	$208,594	$670,891	$ 126,621,986
Average Rates								
Distribution	0.0277663	0.0216751	0.0202782	0.0100870	0.0070331	0.0002132	0.0134137	
Transmission								
Generation (SOS)								
Weather Corrected Delivered Sales (Kwh)	**1,921,357,801**	**1,024,089,262**	**1,294,601,657**	**620,556,320**	**2,446,093,008**	**978,370,640**	**50,015,408**	8,335,084,096
Weather Corrected Revenue								
Distribution*	$ 53,348,933	$ 22,197,205	$ 26,252,240	$ 6,259,557	$ 17,203,516	$ 208,594	$ 670,891	126,140,936
Transmission								
Generation (SOS)								
Total	**$ 53,348,933**	**$ 22,197,205**	**$ 26,252,240**	**$ 6,259,557**	**$17,963,859**	**$ 208,594**	**$ 670,891**	126,901,279
Variance From Booked Revenue								
Distribution	$ (779,356)	$ 961,012	$ 75,217	$ 21,979	$ 458	$ -	$ -	279,310
Transmission								
Generation (SOS)								
Total	**$ (779,356)**	**$ 961,012**	**$ 75,217**	**$ 21,979**	**$ 458**	**$ -**	**$ -**	279,310
Percent Variance From Booked Revenue								
Total	-1.44%	4.53%	0.29%	0.35%	0.00%	0.00%	0.00%	0.22%

* Distribution Revenue based on average rate derived from non-customer charge-related rate components.

PSC DOCKET NO. 13-115
ATTORNEY GENERAL OF THE STATE OF DELAWARE
FOLLOW UP SET OF COST OF SERVICE DATA REQUESTS
TO DELMARVA POWER & LIGHT COMPANY

Question No. : AG-COS-25

Re: the response to AG-COS-19 providing summary results of statistical tests used by the Company to verify the accuracy of load research sampling:

a. Provide the sample skewness and sample kurtosis for each of the four load research samples (profiles) referenced in Attachment 1.
b. Provide summary statistics analogous to information presented in Attachment 1 using test year billing data.
c. In reference to the Company's response to (b) above, provide sample skewness and sample kurtosis for each of the Company's four load research samples (profiles).
d. Provide all internal documents the Company has in its possession regarding Company policy for the updating of Company load research samplings.
e. Responses to parts (a), (b), (c), and (d) above should be provided in electronic form, with all spreadsheet links and formulas intact, source data used, and all assumptions and calculations explained. To the extent the data requested is not available in the form requested, provide the information in the form that most closely matches what has been requested.

RESPONSE:

a. The requested tests were not performed.
b. The requested analyses have not been performed.
c. The requested tests have not been performed.
d. Delmarva has no written policy on sample renewal but relies on the quality of current sample load data statistics to dictate sample maintenance needs.
e. Refer to parts a, b, c and d.

Respondent: Elliott P. Tanos

PSC DOCKET NO. 13-115
ATTORNEY GENERAL OF THE STATE OF DELAWARE
FIRST SET OF RATE DESIGN DATA REQUESTS
TO DELMARVA POWER & LIGHT COMPANY

Question No. : AG-RD-25

Re: statement in Santacecilia Direct, page 4, lines 7-10 that "The remaining increase would then be spread to all service classifications equally. As an overarching cap, a service classification could not receive an increase of more than approximately 150% of the overall average delivery percentage increase."

a. State the basis of which the remaining increase is spread to all service classifications.

b. State the reasons the 150 percent was selected as the limit.

c. Provide any other limitations that were considered and the results of each limit considered.

d. Provide all workpapers and source documents supporting the Company's response in electronic form, with all spreadsheet links and formulas intact, source data used, and explain all assumptions and calculations used. To the extent the data requested is not available in the form requested, provide the information in the form that most closely matches what has been requested.

RESPONSE:

a. The remaining increase is spread to all service classifications based on their current distribution revenue as a percent of the total distribution revenue.
b. The 150% limit on any distribution increase was proposed in Docket No. 09-414. However, since the parties settled that docket with respect to rate design using an across the board revenue allocation, the record is quiet on the issue.
c. No other limitations were considered in this case.
d. See Schedule (MCS)-1.

Respondent: Marlene C. Santacecilia

PSC DOCKET NO. 13-115
ATTORNEY GENERAL OF THE STATE OF DELAWARE
FOLLOW UP SET OF RATE DESIGN DATA REQUESTS
TO DELMARVA POWER & LIGHT COMPANY

Question No. : AG-RD-44

Re: Schedule MCS-1: Provide a detailed narrative explaining the Company's methodology in calculating the customer charge increases for each class, Specifically, why will some classes see rate increases upwards of 50 percent while others will see less?

RESPONSE:

Customer charges were increased to the level indicated by the COSS component allocation. That increase was capped at a 50% increase above the current rate. Any cost allocation where costs allocated to the customer charge did not force the application of the 50% cap were increased by some percentage less than 50%. See also AG-RD-37 b. and c.

Respondent: Marlene C. Santacecilia

PSC DOCKET NO. 13-115
DELAWARE PUBLIC SERVICE COMMISSION STAFF
INITIAL SET OF CONSTRUCTION PROGRAM DATA REQUESTS
TO DELMARVA POWER & LIGHT COMPANY

Question No. : PSC-CP-6

Provide the company's most recent five year SAIDI, SAIFI, and MAIFI compared to Mid-Atlantic Census Division.

a. Confirm that the comparison reflects Major Events Not Included, where applicable.

RESPONSE:

Delmarva notes that the Mid-Atlantic region's yearly median SAIFI and SAIDI are derived from the annual IEEE Benchmark Survey. The specific values were not tabulated in the benchmark survey; rather, they are manually calculated by using the regional code for participating companies. These are IEEE MED Exclusive values.

Reliability Performance	2008	2009	2010	2011	2012
SAIDI - DPL (DE)	213	190	199	192	146
SAIDI - Mid Atlantic (Median Value)	160	138	134	169	129
SAIFI - DPL (DE)	1.47	1.35	1.47	1.41	1.14
SAIFI - Mid Atlantic (Median Value)	1.34	1.35	1.28	1.30	1.00

Respondent: Michael W. Maxwell

PSC DOCKET NO. 13-115
ATTORNEY GENERAL OF THE STATE OF DELAWARE
FIRST SET OF GENERAL DATA REQUESTS
TO DELMARVA POWER & LIGHT COMPANY

Question No. : AG-GEN-1

AG-G Provide all supporting workpapers and source documents for the testimony, exhibits, and rate filing schedules sponsored by Company Witnesses Tanos, Santacecilia, Boyle and Maxwell. Provide the requested documents in electronic form with all spreadsheet links and formulas intact, source data used, and explain all assumptions and calculations used. To the extent the data requested is not available in the form requested, provide the information in the form that most closely matches what has been requested.

RESPONSE:

Testimony and schedules in their native format were sent by separate email for all witnesses on June 21, 2013. In addition, please see Attachments 1 thru 4 for source documents for Company Witness Boyle and Attachments A through D for Company Witness Maxwell. See also responses to AG-REL-44 and 45 for workpapers regarding reliability performance.

Respondent: Delmarva

Delmarva Power - Delaware 2002 - Q1 2013 Actual Distribution Expenditures

	2002	2003	2004	2005	2006
Distribution					
Customer Driven	15,916,660	16,868,173	20,817,436	19,188,489	23,148,073
Reliability	2,747,355	15,527,289	18,104,502	12,420,000	14,591,695
Load	7,159,858	8,024,393	7,286,053	5,500,612	4,857,928
Total	25,823,874	40,419,855	46,207,991	37,109,101	42,597,696

	2007	2008	2009	2010	2011	2012	2013 through 3/31/13
Distribution							
Customer Driven	23,313,180	18,169,398	11,150,572	14,260,410	9,601,683	12,627,540	3,408,389
Reliability	15,738,278	23,999,188	27,705,262	30,965,093	40,957,257	64,095,490	8,713,464
Load	1,407,332	4,727,845	13,386,180	6,430,569	1,026,546	2,797,930	793,523
Total	40,458,789	46,896,432	52,242,014	51,656,072	51,585,486	79,520,960	12,915,377

DPL Delaware Distribution Capital Budget and Plan

	2013	2014	2015	2016	2017
Distribution					
Customer Driven	12,105,059	11,890,891	12,135,731	12,604,197	12,950,259
Reliability	71,413,866	58,910,836	59,232,869	60,273,689	59,249,788
Load	4,308,025	6,135,021	4,308,764	4,482,770	7,407,919
Total	87,826,950	76,936,748	75,677,364	77,360,656	79,607,966

Delmarva Delaware 2007 - Q1 2013 Distribution Capital Budgets

	2007	2008	2009	2010	2011	2012	Q1 2013
Distribution							
Customer Driven	22,489,949	23,345,398	21,588,663	14,803,267	12,265,320	11,878,730	2,974,046
Reliability	12,582,606	26,308,301	24,711,194	32,199,325	41,671,632	60,078,977	19,931,268
Load	2,686,294	4,723,167	12,264,815	6,445,120	1,461,336	2,720,320	1,535,997
Total	37,758,849	54,376,865	58,564,672	53,447,712	55,398,288	74,678,027	24,441,311

1/18/2013 **2011 - 2017 DPL - DE Comprehensive Reliability Budget & Actuals**

DPL *DE*	Budget	2011 *Budget*	2012 *Budget*	2013 *Budget*	2014 *Budget*	2015 *Budget*	2016 *Budget*	2017 *Budget*
	Priority Feeder Upgrades	2,715,792	3,809,725	5,040,163	5,008,191	5,074,711	5,023,813	5,149,406
	Underground Residential Distribution Cable Upgrades (URD)	2,797,597	5,758,245	4,976,044	5,041,317	5,080,518	5,130,351	5,173,937
	Distribution Automation	5,002,899	6,761,404	4,614,290	5,645,946	7,402,598	7,865,544	8,076,344
	Feeder Reliability Improvements	2,725,700	5,371,907	10,381,760	10,873,448	13,025,930	13,168,462	13,497,673
>>	Conversions			1,441,523	0	0	0	0
	Substation Reliability Improvements		3,080,886	5,814,544	4,131,566	3,865,015	4,219,658	5,541,917
	Feeder Load Relief	987,360	2,720,320	3,637,699	5,627,493	3,797,420	3,967,610	6,879,880
	TOTALS	14,229,348	27,502,487	35,906,023	36,327,961	38,246,192	39,375,438	44,319,157

Actual Expenditures	2011 *As of 12/2011*	2012 *As of 12/2012*	2013 *As of 3-31-13*
Priority Feeder Upgrades	2,905,577	5,832,319	811,941
Underground Residential Distribution Cable Upgrades (URD)	3,837,509	5,674,580	1,419,556
Distribution Automation	2,053,809	5,890,246	2,138,966
Feeder Reliability Improvements	1,467,543	4,830,102	1,231,126
Conversions			742,360
Substation Reliability Improvements		1,982,713	926,803
Feeder Load Relief	1,303,775	2,281,930	680,271
TOTALS	11,568,213	26,491,891	7,951,022

	Project Name	Short Description	2011	2011 A As of 12/2011
PF Upgrade	UDLBRM4MF	Millsboro - Priority Circuit Improvement	481,869	1,361,055
	UDLBRM4MK	Millsboro Priority Feeder Rebuild	0	
	UDLNRM4CF	Christiana - Priority Ckt Improvement	1,512,906	1,334,564
	UDLNRM4CK	Priority Feeder Rebuild: Christiana	721,017	209,958
		TOTAL	2,715,792	2,905,577
URD	UDLBRM4MC	Millsboro - Replace Deteriorated URD Cable	636,492	759,646
	UDLBRM4MD	Millsboro - Planned URD Cable Replacement	1,200,000	2,004,031
	UDLNRM4CC	Christiana - Replace Deteriorated URD Cable	961,105	1,073,832
		TOTAL	2,797,597	3,837,509
DA	UDLBRDA1D	Distribution Automation - Bay DE	570,727	1,063,871
	UOIBRASRD	UF Install ASR Computer	144,908	2,555
	UDSBRDA1D	Substation Distribution Automation Bay DE	437,987	200,647
	UORBOBR1M	MI Comm Work - Collector to Data Network	441,936	88,494
	UORBODA1M	Millsboro Comm Work - Install Radios in Line Equip	324,168	57,591
	UORBORBSM	BBW Base Station - Install Millsboro	266,570	62,419
	UORBORSSM	Millsboro Sub Subscriber - BBW	201,659	
	UDLNRDA1C	Distribution Automation: Christiana District	1,045,169	
	UOINRASRD	UF Install ASR Computer	144,908	79,502
	UDSNRDA1C	Distribution Automation: Christiana Substations	389,750	154,396
	UORNOBR1C	CH Comm Work - Collector to Data Network	375,928	196,004
	UORNODA1C	Christiana Comm Work - Install Radios in Line Equipment	222,709	46,907
	UORNORBSC	BBW Base Station - Install Christiana	234,210	101,423
	UORNORSSC	Christiana - Sub Subscriber - BBW	202,270	
		TOTAL	5,002,899	2,053,809
Feeder REL	UDLBRM63M	Millsboro: Feeder Reliability Improvement	583,484	627,540
	UDLNRM63C	Christiana Feeder Reliability Improvements	2,142,216	840,003
		TOTAL	2,725,700	1,467,543
			13,241,988	
Feeder LR	UDLBLBR1	Lakeside: Construct 2 New Feeders	0	
	UDLBLFP2	Five Points - Construct New Feeder	0	
	UDLBLM7M	Millsboro - Feeder Load Relief	711,702	458,271
	UDLBLM7M.1	**Millsboro - Distribution VAR Correction**	0	
	UDLBLM7M.2	**Install Dist Regulators- Fdr Load Relief - Millsboro**	0	
	UDLBLM7M.22	**Nr Seaford DE0516: R/C 1.75 miles of Feeder**	0	
	UDLBLM7M.33	Five Points DE0528: Double Leg Getaway & Add Recloser	0	
	UDLBLM7M.7	Cedar Neck DE0532: Double-leg Getaway&Install Reclosers	0	
	UDLBLM7M.9	Harbeson Sub: Swap Feeders 2270 & 2237	0	
	UDLBLMG1	Magnolia Area 230/25kV Substation: Build two new 25kV Distribut	0	
	UDSBLFP1	Five Points Sub - T2 Add New Brkr	0	
	UDSBLM72A	Clayton Sub Replace T3	31,157	5,501
	UDSBLM7D	Future Projects Dist Sub Bay DE	0	
	UDSBLMG2	Magnolia Area 230/25kV Substation-Build New Substation	0	
	UDLNLCBC2	Mount Pleasant T2: Extend a New Feeder	0	
	UDLNLM7C	Christiana - Feeder Load Relief	244,501	840,003
	UDLNLM7C.1	**Christiana - Distribution VAR Correction**	0	
	UDLNLM7C.10	Valley Road: Establish 12 kV Exit Feeders	0	
	UDLNLM7C.2	Install Dist Regulators - Fdr Load Relief- Christiana	0	
	UDLNLM7C.21	Churchman's DE0256: Reconductor Getaway	0	
	UDLNLM7C.4	Bear 12kV: Parallel exit cable DE0755	0	
	UDSNLM7	Future Projects	0	
	UDSNLM7D	**Future Projects**	0	
	UDSNLM70A	West Wilmington: Replace Low-Side Configuration	0	
	UDSNLM78A	Red Lion - Add 2nd 138/25kV Transformer	0	
	UDSNLM78B	Reybold - Increase T1 & T2 emergency rating	0	
	UDSNLMC1	Montchanin Sub: Install New 34/12kV Transformer and Switchgear	0	
	UDSNLVR1	Valley Road Sub: Install 138/12kV Transformer & Swgr	0	
	UDSNLVR1	Valley Road Sub: Install 138/12kV Transformer & Swgr	0	
			987,360	1,303,775
			14,229,348	11,568,213

Compan	Project Name	Short Description	2012	2012 Actuals as of 12/31/2012
DPL-DE				
PRI FDR	UDLBRM4MF	Millsboro - Priority Circuit Improvement	1,494,110	795,059
	UDLNRM4CF	Christiana - Priority Ckt Improvement	2,315,615	5,037,261
		TOTAL	3,809,725	5,832,319
URD	UDLBRM4MC	Millsboro - Replace Deteriorated URD Cable	751,172	929,715
	UDLBRM4MD	Millsboro - Planned URD Cable Replacement	2,536,257	3,148,970
	UDLNRM4CC	Christiana - Replace Deteriorated URD Cable	1,005,986	703,978
	UDLNRM4CD	Christiana - Planned URD Cable Replacement	1,464,830	891,918
	UDLNRM5CA	IR: Christiana - URD Infrastructure Replacements	0	
		TOTAL	5,758,245	5,674,580
DA	UDLBRDA1D	Distribution Automation - Bay DE	751,526	397,950
	UDSBRDA1D	Substation Distribution Automation Bay DE	463,469	924,674
	UOIBRASRD	Install ASR Computer: Bay DE	132,725	121,397
	UDLNRDA1C	Distribution Automation: Christiana District	1,036,068	184,726
	UDSNRD8MD	Scada/RTU Upgrade NC DE Dist Sub	188,184	57,605
	UDSNRDA1C	Distribution Automation: Christiana Substations	1,453,506	3,363,047
	UOINRASRD	Install ASR Computer: NC DE	187,498	167,057
	UORBOBR1M	MI Comm Work - Collector to Data Network	271,455	64,175
	UORBODA1M	Millsboro Comm Work - Install Radios in Line Equip	263,663	-12,552
	UORBORBSM	BBW Base Station - Install Millsboro	358,121	14,964
	UORBORBTM	Millsboro Comm Work - Upgr Radios in Line Equip	0	
	UORBORCPM	Millsboro: Install Radio Control for Cap Contrl	0	
	UORBORSSM	Millsboro Sub Subscriber - BBW	272,775	
	UORNOBR1C	CH Comm Work - Collector to Data Network	258,206	286,224
	UORNODA1C	Christiana Comm Work - Install Radios in Line Equipmer	429,811	173,459
	UORNORBSC	BBW Base Station - Install Christiana	254,789	32,669
	UORNORBTC	Christiana Comm Work: Upgrade Radios in Line Equip	0	
	UORNORCPC	Install Radio Control for Cap Cntrl-Christiana	0	
	UORNORSSC	Christiana - Sub Subscriber - BBW	439,608	114,852
		TOTAL	6,761,404	5,890,246
	UDLBRM63M	Millsboro: Feeder Reliability Improvement	2,568,671	2,647,888
	UDLBRM4MK	Millsboro Priority Feeder Rebuild	0	
	UDLNRM4CK	Priority Feeder Rebuild: Christiana	0	
	UDLNRM63C	Christiana Feeder Reliability Improvements	2,803,236	2,182,214
	UDSBRM61D	Bay - DE Sub Comprehensive Reliability Impvts	1,505,615	
	UDSNRM61D	NC - DE Sub Comprehensive Reliability Impvts	1,575,271	1,982,713
		TOTAL	8,452,793	6,812,816
			3,080,886	1,982,713
			5,371,907	4,830,102
LOAD	UDLBLFP2	Five Points - Construct New Feeder		
	UDLBLM7M	Millsboro - Feeder Load Relief	1,355,764	886,425
	UDLBLM7M.1	Millsboro - Distribution VAR Correction		
	UDLBLM7M.12	Cedar Neck DE0531: Reconductor Downstream Conductor		
	UDLBLM7M.13	Cedar Neck DE0531: Reconductor Getaway		
	UDLBLM7M.2	Install Dist Regulators- Fdr Load Relief - Millsboro		
	UDLBLM7M.6	Five Points DE0528: R/C & Install Reclosers		
	UDLBLM7M.7	Cedar Neck DE0532: Double-leg Getaway&Install Reclosers		
	UDLBLM7M.21	Five Points DE0527: Reconductor Downstream		
	UDLBLM7M.22	Midway DE0510: Install Recloser to Increase Relay Load Limit		
	UDLBLM7M.28	Felton DE2247: Install Switch for New Normal Open		
	UDLBLMG1	Magnolia Area 230/25kV Substation: Build two new 25kV Distribution Lines		
	UDSBLFP1	Five Points- T2 Add New Brkr		
	UDSBLM72A	Clayton Sub Replace T3	697,263	557,815
	UDSBLM72B	Cedar Neck T1: Upgrade Bus	68,854	36,003
	UDSBLM73A	Millsboro T2: Upgrade Disconnect Switch	12,305	
	UDSBLM73B	Midway: Install 2nd 69/12kV Transformer		
	UDSBLM76A	Cedar Neck: Install 2nd 69/12kV Transformer		400,644
	UDSBLM7D	Future Projects Dist Sub Bay DE		
	UDSBLMG2	Magnolia Area 230/25kV Substation-Build New Substation		
	UDLNLM7C	Christiana - Feeder Load Relief	73,683	
	UDLNLM7C.10	Christiana - Distribution VAR Correction		71,787
	UDLNLM7C.11	Bear DE0750: Reconductor the Getaway	0	
	UDLNLM7C.17	Mermaid DE0745: Reconductor Getaway/Add Recloser	0	
	UDLNLM7C.2	Install Dist Regulators - Fdr Load Relief- Christiana	0	
	UDSNLM72A	W. Wilmington Sub Bus & Brkr Upgrade	512,451	
	UDSNLM7D	NC-DE Future projects	0	329,256
			2,720,320	2,281,930

Company	Project Name	Short Description	2013	2013 As of 3-31-13
DPL-DE				
PRI FDR	UDLBRM4MF	Millsboro - Priority Circuit Improvement	2,501,875	607,843
	UDLNRM4CF	Christiana - Priority Ckt Improvement	2,538,288	204,098
		TOTAL	5,040,163	811,941
URD	UDLBRM4MC	Millsboro - Replace Deteriorated URD Cable	678,281	100,662
	UDLBRM4MD	Millsboro - Planned URD Cable Replacement	1,776,909	555,014
	UDLNRM4CC	Christiana - Replace Deteriorated URD Cable	903,213	185,577
	UDLNRM4CD	Christiana - Planned URD Cable Replacement	1,617,641	578,303
		TOTAL	4,976,044	1,419,556
DA	UDLBRDA1D	Distribution Automation - Bay DE	0	
	UDSBRDA1D	Substation Distribution Automation Bay DE	17,795	-7,935
	UOIBRASRD	Install ASR Computer: Bay DE	7,843	14,547
	UDLNRDA1C	Distribution Automation: Christiana District	1,508,748	49,630
	UDSNRD8MD	Scada/RTU Upgrade NC DE Dist Sub	304,054	
	UDSNRDA1C	Distribution Automation: Christiana Substations	823,380	749,202
	UOINRASRD	Install ASR Computer: NC DE	223,264	6,663
	UORBOBR1M	MI Comm Work - Collector to Data Network	0	
	UORBODA1M	Millsboro Comm Work - Install Radios in Line Equip	0	
	UORBORBSM	BBW Base Station - Install Millsboro	168,270	432
	UORBORBTM	Millsboro Comm Work - Upgr Radios in Line Equip	0	
	UORBORCPM	Millsboro: Install Radio Control for Cap Contrl	19,270	
	UORBORSSM	Millsboro Sub Subscriber - BBW	145,735	106,431
	UORNOBR1C	CH Comm Work - Collector to Data Network	313,987	99,281
	UORNODA1C	Christiana Comm Work - Install Radios in Line Equipment	437,553	9,914
	UORNORBSC	BBW Base Station - Install Christiana	314,066	542,993
	UORNORBTC	Christiana Comm Work: Upgrade Radios in Line Equip	0	
	UORNORCPC	Install Radio Control for Cap Cntrl-Christiana	0	
	UORNORSSC	Christiana - Sub Subscriber - BBW	330,325	567,808
		TOTAL	4,614,290	2,138,966
	UDLBRM63M	Millsboro: Feeder Reliability Improvement	4,324,605	997,360
	UDLNRM63C	Christiana Feeder Reliability Improvements	6,057,151	233,765
	UDSBRD9SF	IR: Millsboro Sub - T1 Replacement	1,466,838	139,428
	UDSBRD9SG	IR: Nr Seaford Sub - T1 & T2 Replacement	282,050	
	UDSBRD9SJ	IR: Kent Sub - T2 Replacement	0	
	UDSBRD9SL	IR: Bethany Sub - T2 Replacement	0	
	UDSBRM61D	Bay - DE Sub Comprehensive Reliability Imprvts	0	
	UDSNRD8KD	DPL DE - Switchgear replacements	0	
	UDSNRD9KA	Milford Crossroads Sub - Switchgear replacements	1,818,832	19,410
	UDSNRD9KB	Bear Sub - Switchgear replacements	1,699,116	17,656
	UDSNRD9KC	Naamans Sub - Switchgear replacements	0	0
	UDSNRD9KD	Mermaid Sub - Switchgear replacements	0	0
	UDSNRD9KE	West Wilmington Sub - Switchgear replacements	0	0
	UDSNRD9KF	Churchmans Sub - Switchgear replacements	0	0
	UDSNRD9KG	Milltown Sub - Switchgear replacements	0	0
	UDSNRD9KH	Sunset Lake Sub - Switchgear replacements	0	0
	UDSNRD9KJ	Tallyville Sub - Switchgear replacements	0	0
	UDSNRM61D	NC - DE Sub Comprehensive Reliability Imprvts	547,708	750,309
		TOTAL	16,196,304	2,157,929
			5,814,544	926,803
			10,381,760	1,231,126
	UDLBRM8BA	Greenwood: 4-25kV Conversion	745,726	555,788
	UDLBRM8BB	Wyoming-Convert to 25kV Ckt 2233 (Phase II)	695,797	186,571
			1,441,523	742,360
LOAD	UDLBLFP2	Five Points - Construct New Feeder	0	0
	UDLBLM7M	Future Projects Dist Line Millsboro	0	0
	UDLBLM7M	Millsboro - Feeder Load Relief	528,992	38,665
	UDLBLM7M.1	Millsboro - Distribution VAR Correction		
	UDLBLM7M.13	Rehoboth Sub: Move Feeder 521 from T1 to T2		
	UDLBLM7M.2	Install Dist Regulators- Fdr Load Relief - Millsboro		
	UDLBLM7M.6	Five Points DE0528: R/C & Install Reclosers	0	0
	UDLBLMG1	Magnolia Area 230/25kV Substation: Build two new 25kV Distributio	0	0
	UDSBLFP1	Five Points- T2 Add New Brkr	0	0
	UDLBLMW2	Midway: Extend New Feeder	0	0
	UDSBLM72A	Clayton Sub Replace T3	55,876	48,280
	UDSBLM73A	Millsboro T2: Upgrade Disconnect Switch	37,124	1,727
	UDSBLM73B	Midway Substation: Install New Transformer		
	UDSBLM73C	Harbeson Sub: Upgrade T-1	1,680,396	262,180
	UDSBLM76A	Cedar Neck: Install 2nd 69/12kV Transformer	430,482	
	UDSBLM7D	Future Projects Dist Sub Bay DE	0	0
	UDSBLMG2	Magnolia Area 230/25kV Substation-Build New Substation	0	0
	UDLNLCBC2	Mount Pleasant T2: Extend a New 25 kv Fdr	0	0
	UDLNLM7C	Future Projects Dist Line Christiana	0	0
	UDLNLM7C	Christiana - Feeder Load Relief	453,340	
	UDLNLM7C.10	Christiana - Distribution VAR Correction		
	UDLNLM7C.11	Bear DE0752: Reconductor the Getaway		
	UDLNLM7C.17	Mermaid DE0745: Reconductor Getaway/Add Recloser	0	0
	UDLNLM7C.2	Install Dist Regulators - Fdr Load Relief- Christiana	0	0
	UDLNLM7C.21	Churchman's DE0256: Reconductor Getaway	0	0
	UDSNLM72A	W Wilmington Sub bus and breaker upgrade	451,489	329,418
	UDSNLM7D	NC-DE Future projects	0	0
			3,637,699	680,271

Company	txtItxtF	Project Name	Short Description	2014	2015	2016	2017
DPL-DE							
PRI FDR	S R	UDLBRM4MF	Millsboro - Priority Circuit Improvement	2,500,000	2,500,000	2,500,000	2,562,500
	S R	UDLNRM4CF	Christiana - Priority Ckt Improvement	2,508,191	2,574,711	2,523,813	2,586,906
			TOTAL	5,008,191	5,074,711	5,023,813	5,149,406
URD	S R	UDLBRM4MC	Millsboro - Replace Deteriorated URD Cable	674,033	685,884	703,031	720,607
	S R	UDLBRM4MD	Millsboro - Planned URD Cable Replacement	1,775,000	1,775,000	1,775,000	1,775,000
	S R	UDLNRM4CC	Christiana - Replace Deteriorated URD Cable	980,136	1,007,486	1,040,172	1,066,183
	S R	UDLNRM4CD	Christiana - Planned URD Cable Replacement	1,612,148	1,612,148	1,612,148	1,612,148
			TOTAL	5,041,317	5,080,518	5,130,351	5,173,937
DA	S R	UDLBRDA1D	Distribution Automation - Bay DE	500,000	1,000,000	500,000	512,500
	S R	UDSBRDA1D	Substation Distribution Automation Bay DE	403,227	412,576	422,065	431,700
	S R	UOIDRASRD	Install ASR Computer: Bay DE	45,078	46,119	47,176	48,251
	S R	UDLNRDA1C	Distribution Automation: Christiana District	504,005	996,791	1,501,367	1,529,804
	S R	UDSNRD8MD	Scada/RTU Upgrade NC DE Dist Sub	300,864	128,453	129,046	129,640
	S R	UDSNRDA1C	Distribution Automation: Christiana Substations	508,173	892,914	1,339,378	1,274,485
	S R	UOINRASRD	Install ASR Computer: NC DE	197,288	199,900	202,511	205,121
	S I	UORBOBR1M	MJ Comm Work - Collector to Data Network	387,341	397,678	419,684	437,061
	S O	UORBODA1M	Millsboro Comm Work - Install Radios in Line Equip	317,369	397,445	401,898	411,131
	S O	UORBORBSM	BBW Base Station - Install Millsboro	177,380	183,681	187,250	190,909
	S O	UORBORBTM	Millsboro Comm Work - Upgr Radios in Line Equip	0	150,000	150,000	153,750
	S O	UORBORCPM	Millsboro: Install Radio Control for Cap Contrl	337,820	344,956	356,990	365,934
	S O	UORBORSSM	Millsboro Sub Subscriber - BBW	162,463	167,056	168,478	169,900
	S I	UORNOBR1C	CH Comm Work - Collector to Data Network	341,306	381,498	407,664	416,970
	S O	UORNODA1C	Christiana Comm Work - Install Radios in Line Equipment	451,194	461,785	476,166	487,928
	S O	UORNORBSC	BBW Base Station - Install Christiana	335,351	386,698	394,144	415,930
	S O	UORNORBTC	Christiana Comm Work: Upgrade Radios in Line Equip	0	150,000	150,000	153,750
	S O	UORNORCPC	Install Radio Control for Cap Cntrl-Christiana	325,410	325,340	325,637	333,851
	S O	UORNORSSC	Christiana - Sub Subscriber - BBW	351,677	379,708	386,090	407,729
			TOTAL	5,645,948	7,402,598	7,865,544	8,076,344
	S R	UDLBRM63M	Millsboro: Feeder Reliability Improvement	4,904,270	5,951,874	6,000,674	6,150,691
	S R	UDLNRM63C	Christiana Feeder Reliability Improvements	5,969,178	7,074,056	7,167,788	7,346,982
	S R	UDSBRD9SF	IR: Millsboro Sub - T1 Replacement	5,274	0	0	0
	S R	UDSBRD9SO	IR: Nr Seaford Sub - T1 & T2 Replacement	1,708,489	207,308	0	0
	S R	UDSBRD9SJ	IR: Kent Sub - T2 Replacement	0	0	0	0
	S R	UDSBRD9SL	IR: Bethany Sub - T2 Replacement	0	0	0	0
	S R	UDSBRM61D	Bay - DE Sub Comprehensive Reliability Imprvts	0	859,433	870,930	990,779
	S R	UDSNRD8KD	DPL DE - Switchgear replacements	0	0	0	2,999,768
	S R	UDSNRD9KA	Milford Crossroads Sub - Switchgear replacements	0	0	0	0
	S R	UDSNRD9KB	Bear Sub - Switchgear replacements	0	0	0	0
	S R	UDSNRD9KC	Naamans Sub - Switchgear replacements	1,371,929	0	0	0
	S R	UDSNRD9KD	Mermaid Sub - Switchgear replacements	795,874	0	0	0
	S R	UDSNRD9KE	West Wilmington Sub - Switchgear replacements	0	1,559,804	0	0
	S R	UDSNRD9KF	Churchmans Sub - Switchgear replacements	0	988,470	0	0
	S R	UDSNRD9KG	Milltown Sub - Switchgear replacements	0	0	1,369,327	0
	S R	UDSNRD9KH	Sunset Lake Sub - Switchgear replacements	0	0	1,729,401	0
	S R	UDSNRD9KI	Tallyville Sub - Switchgear replacements	0	0	0	1,301,370
	S R	UDSNRM61D	NC - DE Sub Comprehensive Reliability Imprvts	250,000	250,000	250,000	250,000
			TOTAL	15,005,014	16,890,945	17,388,120	19,039,590
				4,131,566	3,865,015	4,219,658	5,541,917
				10,873,448	13,025,930	13,168,462	13,497,673
	S R	UDLBRM8BA	Greenwood: 4-25kV Conversion		0	0	0
	S I	UDLBRM8BB	Wyoming-Convert to 25kV Ckt 2233 (Phase II)		0	0	0
				0	0	0	0
LOAD	S I	UDLBLFP2	Five Points - Construct New Feeder	0	0	0	0
	S I	UDLBLM7M	Future Projects Dist Line Millsboro	250,000	325,000	350,000	350,000
	S I	UDLBLM7M	Millsboro - Feeder Load Relief				
	S I	UDLBLM7M.1	Millsboro - Distribution VAR Correction	254,027	263,282	265,256	267,228
	S I	UDLBLM7M.13	Rehoboth Sub: Move Feeder 521 from T1 to T2	0	0	0	0
	S I	UDLBLM7M.2	Install Dist Regulators- Fdr Load Relief - Millsboro	117,731	134,054	134,507	134,960
	S I	UDLBLM7M.6	Five Points DE0528: R/C & Install Reclosers	0	0	0	0
	S I	UDLBLMG1	Magnolia Area 230/25kV Substation: Build two new 25kV Distributio	0	0	0	0
	S I	UDSBLFP1	Five Points - T2 Add New Bkr	0	0	0	0
	S I	UDLBLMW2	Midway: Extend New Feeder	0	0	0	100,000
	S I	UDSBLM72A	Clayton Sub Replace T3	0	0	0	0
	S I	UDSBLM73A	Millsboro T2: Upgrade Disconnect Switch	0	0	0	0
	S I	UDSBLM73B	Midway Substation: Install New Transformer	0	17,163	736,899	1,613,078
	S I	UDSBLM73C	Harbeson Sub: Upgrade T-1	0	0	0	0
	S I	UDSBLM76A	Cedar Neck: Install 2nd 69/12kV Transformer	3,577,301	594,864	0	0
	S I	UDSBLM7D	Future Projects Dist Sub Bay DE	0	500,000	500,000	1,000,000
	S I	UDSBLMG2	Magnolia Area 230/25kV Substation-Build New Substation	0	0	0	1,696,704
	S H	UDLNLCBC2	Mount Pleasant T2: Extend a New 25 kv Fdr	500,200	506,589	512,974	0
	S I	UDLNLM7C	Future Projects Dist Line Christiana	250,491	505,983	510,997	516,010
	S I	UDLNLM7C	Christiana - Feeder Load Relief				
	S I	UDLNLM7C.10	Christiana - Distribution VAR Correction	273,074	280,712	286,782	294,426
	S I	UDLNLM7C.11	Bear DE0752: Reconductor the Getaway	0	0	0	0
	S I	UDLNLM7C.17	Mermaid DE0745: Reconductor Getaway/Add Recloser	0	0	0	236,865
	S I	UDLNLM7C.2	Install Dist Regulators - Fdr Load Relief- Christiana	139,988	140,413	140,835	141,255
	S I	UDLNLM7C.21	Churchman's DE0256: Reconductor Getaway	0	0	0	0
	S I	UDSNLM72A	W.Wilmington Sub bus and breaker upgrade	0	0	0	0
	S I	UDSNLM7D	NC-DE Future projects	264,681	529,360	529,360	529,360
				5,627,493	3,797,420	3,967,610	6,879,880

PSC DOCKET NO. 13-115
ATTORNEY GENERAL OF THE STATE OF DELAWARE
FIRST SET OF RELIABILITY DATA REQUESTS
TO DELMARVA POWER & LIGHT COMPANY

Question No. : AG-REL-1: Historical Capital Spending

a. For each of the years 2007 through 2012, and for 2013 through the date of your response, state the amount of the Company's actual and budgeted capital spending broken down by plant category.
b. Break down each of the amounts set forth in your response to part (a) by each:
1. FERC USOA account;
2. REP (by project);
3. Non-REP (itemize by project); and
4. Total.
5. Reconcile differences between the total and item (1) and the sum of items (2) and (3) to the total.
c. Provide a detailed explanation for all differences between actual and budgeted amounts set forth in your response to parts (a) and (b) above.
d. For each project referenced in your response to part (b.2) and (b.3) separately, state the amount:
1. Authorized for the project; and
2. Closed to plant by year.
e. Provide all workpapers and source documents supporting the Company's response in electronic form, with all spreadsheet links and formulas intact, source data used, and explain all assumptions and calculations used. To the extent the data requested is not available in the form requested, provide the information in the form that most closely matches what has been requested.

RESPONSE:

a. Refer to the response to AG-GEN-1 Attachment A and C.

b. 1. Capital budgets and expenditures are not prepared by FERC Account.

2. Refer to AG-GEN-1 Attachment D. Note that the Reliability Enhancement Program was not officially approved by Delmarva's Board of Directors until 2010.

3. See Attachment A for "non-REP" actuals and Attachment B for "non-REP" budget.

4. Refer to the response to AG-GEN-1 Attachment A.

5. The requested reconciliation has not been performed.

c. The requested analysis has not been performed.

d. 1.Refer to the response to AG-GEN-1 Attachment A.

2. See the attached: Attachment C.

e. Refer to attachments above.

Respondent: Michael W. Maxwell